Supreme Court, U.S.
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87-178

No.

In the Supreme Court

OF THE

United States

OCTOBER TERM, 1987

PACIFIC GAS AND ELECTRIC COMPANY,
a California Corporation
Petitioner,

v.

PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA,
Respondent.

APPENDIX TO PETITION FOR WRIT OF CERTIORARI TO THE CALIFORNIA SUPREME COURT

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APPENDIX A

Order Denying Alternative Writ

S.F. No. 25114

In the Supreme Court of the State of California

In Bank

Pacific Gas and Electric, Petitioner

v.

Public Utilities Commission, Respondent.

Panelli, J., Did Not Participate

[Filed April 30, 1987]

Petition for Writ of Review DENIED.

/s/ Lucas

Chief Justice

APPENDIX B

Decision 83-09-054 September 7, 1983

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983 and August 2, 1983)

Second Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Instituting Rulemaking No. 2.

Application 82-04-46 (Filed April 21, 1982; amended May 12, 1982; July 11, 1983 and August 10, 1983)

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY for an Order by the California Public Utilities Commission Directing Edison to Purchase Power from Qualifying Facilities Based on a Standard Offer for Firm Capacity and Energy Based on Long-Run Marginal Costs (OIR-2).

Application 82-04-47 (Filed April 21, 1982; amended July 11, 1983, and August 2, 1983)

In the Matter of the Application of SAN DIEGO GAS & ELECTRIC COMPANY for an Order by the California Public Utilities Commission Directing SDG&E to Purchase Power from Qualifying Facilities Based on Standard Offers and to Make Certain Changes or Additions to its Tariffs Affecting Purchases from Qualifying Facilities.

(For appearances see Appendix A.)

INTERIM OPINION

These proceedings involve adopting standard offers based on long-run avoided costs for power purchase contracts between the three largest electric utilities and qualifying facilities (QF). The utilities are: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E).

Before explaining the procedural history which has brought us to this point, we think it is constructive to explain briefly why we have pursued developing such standard offers in view of the standard offers in-place which pay QFs for their power based on actual short-run utility avoided costs.

I. SUMMARY OF DECISION

This decision authorizes what is termed Standard Offer #4, which has different payment options for QFs, all of which are based on forecasts of the utilities' resource mix and costs. The three payment options under Standard Offer #4 resulted from negotiations. A negotiating conference, which lasted five weeks, was held at our direction, with vigorous participation by utilities, QFs, and our staff. We have committed to hold evidentiary hearings, which almost all parties desire. However, there is substantial agreement among utilities, QFs, and our staff that until a more permanent solution is found for the complex task of fairly valuing and pricing QF power over the long-run, Standard Offer #4, with three payment options, should go into effect.

We undertook the negotiating conference in the hope of coming closer to an interim solution which, while not perfect from all perspectives, could be useful for QFs and utilities. While some may have hoped to accomplish more than the scope of the consensus reached, or they would have preferred different results, we think the negotiating conference was extremely fruitful.

The negotiated standard offer and three payment options are approved, with some reasonable restrictions on their use set by us under our prerogative.

Standard Offer #4, at this juncture, is interim in the sense it may ultimately be replaced with a different costing methodology, contract terms, etc. However, until that happens, it may be fully relied on by utilities and QFs who find the options useful. Those who contract under interim Standard Offer #4 will not be subject to having terms or prices changed later, except as narrowly and specifically ordered by this decision. Any changes made to this standard offer in the future will only apply to those contracting after such changes. Potential QFs who find they cannot use Standard Offer #4, as approved today, still have the option of pursuing a negotiated nonstandard contract with utilities.

II. BACKGROUND

Utilities' short-run avoided costs have proven to be more volatile than many observers would have guessed. We have seen a drastic run-up in fuel oil and gas prices, followed by a moderate decline in oil prices. The QF industry contends that the price uncertainty posed under the existing as-available and firm capacity standard offers, both based on short-run avoided costs, makes it extremely difficult to arrange financing for potential QF projects. QFs tell us that those who hold the financing purse-strings, both lenders and equity investors, are reluctant to commit captial when a project's payment stream is so uncertain. Our Decision (D.) 82-01-103 in OIR 2, issued January 21, 1982, recognized the need to pursue developing standard offers based on long-run avoided utility costs (page 67, mimeo.). Oil and gas prices were steadily rising when that decision was issued, and although the three largest electric utilities were ordered to file applications with proposed standard offers based on long-run avoided costs, most of our attention and that of the QF industry was directed to perfecting standard offers based on short-run avoided costs. Many assumed oil prices would continue to rise; few seemed to believe they would start a decline. As oil prices started to decline the intensity of interest in standard offers which would produce prices based on long-run (and presumably less volatile) avoided costs correspondingly increased.

If we do not adopt a standard offer based on long-run avoided costs as an alternative to the existing standard offers, the pressure

for nonstandard contracts between utilities and QFs could steadily increase. Such nonstandard contract negotiations pose problems for all: QFs typically ask for variations of up-front price security or certainty so they can finance projects, and utilities are faced with ensuring the nonstandard contract has suitable terms to make it a secure venture for them and their ratepayers; further, operating under our regulation, utilities are concerned about ultimate cost recovery, and worry that the prudence of nonstandard contracts may be successfully challeged in their energy cost recovery proceedings. Also, the long-term value of new QF capacity in the utilities' resource plans is not fully reflected by the existing standard offers which base prices on fluctuating short-run avoided utility cost (see D.82-01-103, p 67). It is, then, in everyone's interest that a standard offer based on long-run avoided cost be adopted.

The threshold problem is how can long-run avoided costs be determined. Dealing with short-run avoided costs was difficult, but the problems were surmounted and standard offers are in place. However, to value QF power reasonably in the long run, we must make many assumptions about the utilities' future generation mix and costs. While we deal extensively with forecasting the future when ratemaking, the view is only 1-3 years. This does not mean we cannot project the value of QF power for longer periods, say 10-15 years; but it means that the method used to forecast the value of QF power must be one that is not biased at the outset with a likelihood of being too high or too low when, after the test of time, payments to QFs under the forecast are compared to actual avoided costs. Or, from the ratepayer's perspective, there must be an even chance that the forecast will be too high as too low.

There are different ways of arriving at estimates of long-run avoided costs, and the future value of QF power, but all involve proxies or the creation of a utility's generation mix and costs on a composite basis viewed at some future time. The "generation resource plan" approach, for example, would evaluate the (weighted) capacity and energy costs associated with the utility's projected mix of resource additions without the availability of QF power. Some (not the utilities) prefer using a coal plant as the

assumed resource addition that would be deferred by long-term QF power. Another method, discussed later in this opinion, is forecasting short-run avoided costs into the future to capture a proxy of future conditions. Under this approach, the value of QF power is computed on the general assumption that the utility does not make any new plant investments except in some short run peaking capacity to maintain system reliability. Once this value is quantified then various options for paying QFs for their value are applied. Obviously, the longer the forecast the more problematical it is to rely on for valuing QF power and paying QFs, in that we are committed to treating the prices paid under the standard office as per se reasonable, to be passed on to ratepayers.

Some may contend that prices fixed under long-term forecasts can, at least at times, be above actual avoided costs, and therefore both: (1) PURPA will be violated in that payments will exceed avoided costs, and (2) the ratepayers will pay too much. We think the proper view and test is whether over the course of a long-term contract, despite periodic swings in actual avoided costs both above and below a forecast, the prices reasonably compensate QFs for their value in avoiding a utility's costs, and keep the ratepayer economically indifferent to whether the generation was performed by the utility or a QF. As long as there is equal likelihood that swings in actual avoided costs are both below and above the forecast, over the term of forecast based prices, we think the spirit and letter of PURPA are followed.

More troublesome, perhaps, for some is that we are adopting long-term standard offers based on forecasts of escalating avoided utility costs when there is no current capacity shortage among California utilities. The question becomes: why stimulate QF projects which cannot now proceed in the generation marketplace, under the existing as-available or firm capacity offers based on short-run costs, by adopting offers based on long-run utility avoided costs? The answer is that standard offers based on long-run avoided costs are for long-term contract commitments. We would rather err on the side of trying to have QF capacity steadily come on line over time, than on that of ultimately risking a critical capacity shortage because we did not take reasonable steps to afford an opportunity for QF power, particularly long-

term capacity, to be steadily developed. Many of the QF projects that may materialize because of the standard offers we adopt today may not come on line for several years. Also, developing QF power means California will be better able to meet its power needs from within its borders, and the State's resources will be more fully and efficiently used. Finally, we have never said that QF power must be developed at *any* cost, but rather that it should be developed with reasonable cost to ratepayers when viewed in the longer-term perspective. In the long run, if we do a reasonable job of valuing and pricing QF power, the ratepayers should be indifferent as to whether eventually needed capacity is supplied by QFs or electric utilities.

III. PROCEDURAL HISTORY

A. General

A first prehearing conference was held on July 19, 1982 before Administrative Law Judge (ALJ) Myers. Although hearings were not scheduled, procedural issues were raised. On November 18, 1982 we issued a report on the general issued involved in devising standard offers based on long-run avoided costs, and requested comments. We did this primarily to stimulate thinking among the parties on these issues, and to see if there was any consensus on the very tentative conclusions we had reached at that time. Eighteen parties filed comments. Then, on May 4, 1983 we issued D.83-05-038, which set a negotiating conference starting on May 23 at Hastings College of the Law. It was our hope that with good faith negotiations between the utilities, QF interests, our staff, and other interested parties, some tentative agreement could be reached about a standard offer(s); any agreed upon standard offer would, of course, require our ratification.

The ground rules of the negotiating conference were that any standard offers to be proposed to us for consideration should be completely worked out in final form, and that the assent of all interests at the negotiating conference was required before a standard offer would be proposed; this was essential to protect the rights of all parties since there were no evidentiary hearings. The goal, among the parties, was to attempt to develop an interim standard offer which, while not perhaps the perfect preferred

solution from their individual perspectives, would be one which they could comfortably tolerate and work under while refinement and "perfection" could be pursued in subsequent evidentiary hearings. Their understanding, based on our procedural plans as communicated by our ALJ, was that if we approved an agreed upon standard offer it would be an interim measure, subject only to change prospectively after formal hearings. It was also understood that the "final" Standard Offer #4 resulting from evidentiary hearings could, if appropriate after further evaluation, be based on an avoided cost methodology and/or pricing structure that differs from the interim order.

The negotiating conference concluded on June 24, 1983. The ALJ directed the three utilities to amend their respective applications no later than July 11, 1983; their amendments would contain proposed standard offers, complete with contract language, that precisely reflected the consensus agreement reached at the negotiating conference. The ALJ then set a second prehearing conference on Friday, July 22, 1983 to allow parties an opportunity to indicate whether the proposed standard offers should be allowed to go into effect by this Commission pending evidentiary hearings on the multitude of issues surrounding pricing QF power. Again, parties understood throughout the negotiating conference that if it produced some "negotiated" standard offers, which the Commission subsequently approved, they would be afforded an opportunity through the hearing process to propose modifications for prospective applications.

B. The Negotiating Conference Process

This was the first negotiating conference formally arranged and hosted by us. In some respects it is a frustrating process, because consensus building in a relatively unstructured arena (as compared to our hearing process) can be cumbersome. On the other hand, particularly if time limits are set, some consensus can be reached relatively quickly, whereas adversarial hearings on such a complex subject with a polarity of positions can take months longer. This is not to say the negotiating conference was nonadversarial; we understand it was adversarial. In fact, a critical ingredient of this process is that all sides are represented with near-equal resources and clout.

We were fortunate to have our staff coordinated and represented by the Director of the Utilities Division. We would be greatly concerned if our staff had not been an aggressive and key negotiating party, for it would raise the specter of utilities perhaps ultimately reaching the point with QFs of saying, in effect: your proposals do not sound fair, but since our cost recovery is virtually guaranteed if prices are paid under Commission ratified standard offers, what do we care—we will go along. However, neither consensus resolution of issues nor routinely seeking to split the difference, necessarily guarantees the best resolution from the standpoint of the public interest, which is why we must be guarded and very selective in deciding when to use the negotiating conference procedure, and in evaluating its results. We note from the prehearing conference that some QF representatives seem to feel that too much emphasis is placed on whether our staff, as a participant in negotiations, agrees on how an issue is resolved. Vigorous staff participation is an essential ingredient in any arena, and if some parties find staff's direct participation troublesome, it is probably a good indication our staff is doing the aggressive and thorough job we expect.

The most critical aspect of this process is that each agreed upon standard offer resulting from the negotiating conference is presented to us on a take-it-or-leave-it basis. Each was truly negotiated as a "package", comprised of cost forecasts, prices, and contract terms, etc. We are, at this juncture, without an evidentiary record upon which to weigh various proposals and adopt a standard offer reflecting a careful weighing of various components. Essentially, then, we face either accepting or rejecting each of the three standard offer payment options as negotiated, and we do not, in fairness to the parties, have the latitude to make modifications.

C. The Second Prehearing Conference

At the second prehearing conference on July 22, 1983 a number of QFs indicated that while there was substantial agreement that two of the payment options under Standard Offer #4 were complete and acceptable, there were serious reservations remaining with respect to:

1. Option #3, or the forecasted incremental energy rate option, as filed by PG&E and SDG&E; they found Edison's acceptable because they liked Edison's forecast.

2. Option #4, filed by PG&E only, which is a forecasted energy floor price payment option. This was an option not fully developed or addressed during the negotiating conference.

QFs, essentially, asked that the negotiating conference be resumed or that they be allowed to pursue ad hoc negotiations with utilities. They stated a preference not to pursue refining Options #1 and #2 until all issues, from their perspective, relating to all four payment options are resolved. Also, they expressed the opinion that the "Regulatory Authority" clause in Edison's and SDG&E's proposed standard offer must be eliminated, and the issue about contract switching must be resolved.

After conferring with the assigned Commissioner, the ALJ ruled that the prehearing conference would be continued to August 8, 1983, for the specific purpose of allowing utilities to address concerns QFs has about contract language pertaining to Options #1 and #2. Also, he announced that the QFs' request to reopen the negotiating conference would be addressed by the Commission in this decision. QF representatives then listed the particular contract language and areas which, from their perspective, needed nonsubstantive changes so the contracts, mechanically, conformed to the agreement reached at the negotiating conference. Given the list of specified contract language "problem areas", the ALJ directed the utilities to review their contract language with QFs and staff, and to distribute any revised page before the prehearing conference continued. They were directed not to "negotiate", but, rather, to work together to ensure that the contract language is clear and carries out the intent of the negotiated settlement. The ALJ announced that the Commission would address the interrelated issues of contract switching and the contracts' regulatory authority clause in its decision; those issues are discussed later in this opinion.

On August 8 the prehearing conference resumed. An opportunity was extended to all parties to address whether the proposed

Standard Offer #4 payment options should go into effect, whether evidentiary hearings should be held and, if so, what issues should be addressed. There was an array of positions on these matters, as well as on whether the negotiating conference should be reopened.

Edison and SDG&E think the three payment options proposed with Standard Offer #4 should go into effect, and that before hearings are held the reaction and experience under those payment options should be studied and evaluated. Neither utility proposed a floor price mechanism as PG&E did, and they think such a conceptual payment option needs considerable study. PG&E thinks all four of its proposed payment options should go into effect, and it too thinks we should hold off going to hearing until we gain some marketplace experience with interim Standard Officer [sic] #4. While some QFs think further negotiations on PG&E's incremental energy rate forecast would be fruitful (e.g., result in a more favorable forecast), PG&E indicates further negotiations would be futile (PHC transcript, page 156). Edison indicates that at some point the entire areas of costing methodology, payment stream options and, more narrowly security provisions for contracts, should be scrutinized in hearings.

Our staff thinks all the payment options, except the floor price mechanism proposed by PG&E, should go into effect on an interim basis. The floor price mechanism warrants thorough review from the standpoint of ensuring ratepayer economic indifference and protection, and staff believes some "workshop" forum in conjunction with or before evidentiary hearings might be fruitful. Staff is not convinced that this particular payment option can be quickly resolved by negotiations. Staff believes that further efforts at negotiating the incremental energy rate forecast of SDG&E and PG&E so they are acceptable to more QFs would probably not be fruitful. Staff thinks at this juncture the entire subject of costing methodology, valuing long-term QF power, and pricing streams should be the subject of evidentiary hearings.

The California Energy Commission and the State Solid Waste Management Board both want us to direct further negotiations aimed specifically at having SDG&E and PG&E develop incre-

mental energy rate forecasts more favorable to QFs, and adopting a floor price mechanism payment option.

None of the QF representatives who made statements at the prehearing conference had any objection to Payment Options #1 and #2 going into effect for all three utilities. They all thought Edison's Option #3 was acceptable, because they prefer Edison's incremental energy rate forecast over that of either SDG&E or PG&E. Contrary to the views of PG&E, SDG&E and Staff, QFs almost uniformly believe if we direct more negotiations on the incremental energy rate forecasts of PG&E and SDG&E the end result will be more favorable forecasts. We note at this juncture that if we ordered more negotiations on the incremental energy rate forecasts of only two of the three utilities, our action would be taken as a strong signal that we have reason to believe their forecasts are too unfavorable to QFs. We have no facts or evidence to lead us to such a presumption; all we know is that some QFs say they need and would prefer more favorable forecasts. QFs all seem to indicate that if we do not order further negotiations aimed at these forecasts, then we should authorize the incremental energy rate forecast payment option as proposed by SDG&E and PG&E because some QFs may be able to use those payment options.

QFs think the latest floor price mechanism payment option proposed by PG&E is acceptable, and that if we do not totally approve it, and direct the other utilities to include it in their respective standard offers, then we should at least clearly embrace the concept and direct it to be the subject of further negotiations.

Other points raised by some QF representatives are:

1. We ought to clarify whether utilities can still pursue nonstandard contracts with potential QFs who do not find one of the standard offers useful.

2. The question of whether QFs already under contract may switch to Standard Offer #4 should be addressed and resolved, preferably with the result being freedom to switch; and, likewise, whether subsequent versions of Standard Offer #4 that may result after hearings should then be freely available retroactively to QFs who signed a contract under negotiated Standard Offer #4.

Both issues are addressed later in this opinion.

Some QFs want evidentiary hearings, primarily to develop a permanent costing methodology for valuing long-term QF power, to resolve the need for security provisions in contracts, and to pursue adopting methodologies and/or forecasts that are readily verifiable. On this latter point, one goal almost all QFs share is having utilities use a common forecast of long-run marginal costs for pricing QF power and for utility resource planning purposes. This, they say, would result in QFs no longer being "whipsawed" by utilities, which are the ultimate data repositories, using different forecasts for different purposes.

IV. LIMITATIONS ON THE AVAILABILITY OF THE ADOPTED STANDARD OFFER AND CONTRACT SWITCHING

The standard offers we have already adopted are based on utilities' short-run avoided costs, and they set prices which can fluctuate, but which closely parallel actual avoided costs. However, the standard offer addressed by this opinion involve projections, assumed proxies, and payment stream certainty which can have a visible impact on electric bills. This standard offer is the first with such characteristics, and there will undoubtedly be refinements and modifications adopted, for prospective application, as time goes by and experience is gained.

We will adopt some overall limitations on the use of this interim standard offer in recognition that we are not convinced

that it is a permanent all-inclusive solution. Parties agreed, at the negotiating conference, to recommend that the negotiated standard offer be allowed to remain in effect at least six months, but no more than two years. It will probably be at least six months before hearings conclude, so we have no difficulty ordering the offers ratified by this decision to be in effect for at least six months, and until further order.

SDG&E requests that its forecast of marginal operating costs underlying its energy prices be used for a maximum of six months; that issue will be addressed later in this opinion.

Am important point for our resolution is whether existing QFs, already in production and under contract, should be eligible for the standard offer adopted in this decision. At the negotiating conference the utilities asked for some clarification, wanting to avoid a morass of uncertainty and contract administration problems. None of the participants had specific suggestions at the negotiating conference, but all seemed to want some clarity. ALJ Alderson promised to bring the matter to the Commission's attention for resolution.

In the past, when the entire subject of devising standard offers was in its infancy and the existing standard offers based on short-run avoided costs were evolving, we allowed QFs under contract to switch to the standard offer based on short-run costs which ultimately evolved (D.82-01-103, mimeo page 145); subsequently we said: "QFs may not switch from one standard offer to another, but may adopt the final version of the particular offer signed" (D.82-12-120, issued December 30, 1982, in A.82-03-26 et al., mimeo page 118).

We think there are overall problems with contract switching, and the preferred approach in this instance, particularly since the standard offer before us is so fully developed with all contract terms and complete with fixed prices, is for QFs to evaluate it from the basis of making a long-term commitment, for a 15-year minimum term is involved. Accordingly, QFs who sign up under one of the options under this standard offer, albiet interim in one sense, will not be allowed to switch later; they must wait until the end of their contract term.

With respect to QFs already in production, we will allow them to sign up under this standard offer only if they are no longer under contract; QFs who have decided to produce under existing standard offers, and who entered a contract, should be bound by their decision.

Some standard and nonstandard contracts have provisions which allow QFs to elect standard offers which may be approved subsequent to their entering the nonstandard contract. However, the standard offer approved by this decision represents only an interim solution, subject to change after hearings, for prospective application. As such, since we are adopting a standard offer without an evidentiary record, we are not comfortable allowing QFs under contract, even nonstandard contracts, the switch. QFs under standard and nonstandard contracts, with provisions clearly allowing them to switch, may switch after a final standard offer comes into existence after hearing, but for the time being they will have to honor their commitment under the contracts they entered. A critical factor in our thinking is that this standard offer, and the procedures leading to it, resulted primarily from our goal to encourage *new* QF projects which have not yet obtained financing or otherwise entered a contract and started production.

Finally, we will limit the levelization payment option under this standard offer to new QF facilities or those which have never produced and sold power. This is because, with some reluctance, we approve the levelization option as a stimulus for *new* QF projects, and it is not reasonable for ratepayers to bear the cost of levelization in the early years to benefit a QF project or facility which has already managed to obtain financing and start production.

A subject so closely related to contract availability and switching warrants discussion at this point, is our concern about QFs breaching, or otherwise altering the contracts entered under Standard Offer #4.

PG&E's amended application summarizes the overall underlying concern about fixing QF payments based on a forecast or, for that matter, any proxy of anticipated utility avoided costs:

> "We can be certain that actual avoided costs will differ from the forecasts. Locking into a forecast in a rigid way assures that there will be economic losers—either QFs or ratepayers—in the future, because actual avoided costs will either be above or below the forecast. Staff believes that a disadvantaged party won't mind, because there had been an equal chance of being the economic 'winner' at the time the contract was executed. This is good theory, but it defies experience. If one party is seriously disadvantaged by a contract, it will have strong motivation to breach or alter the contract, regardless of how reasonable the contract appeared when it was signed.
>
> "Similarly, PGandE expects that if QFs are disadvantaged by the forecast price options, they will do everything possible to renegotiate, terminate, or otherwise escape their obligations. We have attempted to write the contract to avoid this, but with the amount of money potentially at stake, ways may be found. Conversely, if ratepayers are harmed, we expect accusing fingers to be pointed at PGandE and at the Commission. We trust a future commission would abide by a decision of this one and allow costs to be recovered." (PG&E amended application, Exhibit A, page 4).

We think, QFs may be "winners" at times and "losers" at others, when, at any point in time, originally forecasted avoided costs are compared to actual. However, the recent volatility in short term utility avoided costs caused by oil price fluctuations will probably be borne in mind by QFs electing one of the forecast based payment options under Standard Offer #4. Accordingly, we believe they will think long and hard before seriously attempting to terminate early or to breach their contract. However, we agree with PG&E that some QFs under long term Standard Offer #4 contracts may seek to get out of those contracts if actual avoided cost conditions, particularly over a fairly long duration, would be to their advantage (despite the potential for damages generally

and specific minimum damages clauses in some of the contracts).[1]

We think it is reasonable to order that utilities are under no obligation to enter into any power purchase contract, even under one of the otherwise available Commission approved standard offers, with a QF who has terminated early or breached under Standard Offer #4, payment options approved by this decision, if damages have not been collected. By damages we mean the utility either having collected at least the minimum damages, if the contract has a minimum damages clause, and foreseeable damages if their is no applicable minimum damages clause. Parties should honor their contractual commitments, and we think our making it unattractive for QFs to terminate or switch contracts is only fair, as it balances the risk ratepayers are assuming at the outset with this long-term, forecast based, fixed price, standard offer. While this issue was not specifically raised at the negotiating conference, we think it is our prerogative to take reasonable steps to minimize contract evasion; indeed, under the circumstances it is our duty to the ratepayers.

V. THE STRUCTURE OF STANDARD OFFER #4 AND FUTURE CONTRACT LANGUAGE CONSISTENCY

This opinion will address what is called Standard Offer #4, which contains several payment options. Standard Offer #1 was adopted by D.82-12-120, and is for as-available energy payments; #2 is for firm capacity, and #3 is for smaller QF projects (under 100 kW). The Standard Offer #4 contracts proposed by each of the three utilities has some common contract terms that apply for all options, and specific terms covering the individual payment options. The filed contracts are complete with the agreed upon forecasts, upon which prices will be paid.

Each utility chose its own format and contract language, with the goal, however, of all being consistent in substance (with the

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[1] Minimum damages clauses apply to capacity payments when the firm capacity option is selected for capacity payments, and for energy payments when a levelized payment option is selected. Aside from the minimum damages clauses, utilities may pursue foreseeable damages as apply in any breach of contract situation.

exception of certain agreed to utility specific terms, such as curtailment). As experience is gained with standard offers, and QF power purchase contracts generally, uniform standard contract language should be used by all utilities, except for terms which must clearly be utility specific because of substantitive differences. The convenience of standard language will greatly aid those who must review standard offers. We are disappointed this could not have been done for Standard Offer #4 in the context of the negotiating conference, but it appears time did not permit it. Rather than to simply pick one of the utilities' contracts and order that language used by the others, we will direct the utilities to work together, with our staff, in proposing one form of Standard Offer #4 with uniform language (except where terms must be utility specific). Six months will be allowed for this undertaking, and the product shall be presented during the subsequent hearings for review.

That, we think, is adequate time for the three utilities' and our staff to harmoniously come to some common terms. QFs will have an opportunity to address the uniform Standard Offer in subsequent hearings. Once adopted standard offers are uniform for all utilities, it will be far easier to review and consider proposed changes, and to subsequently review any filed standard offer contracts in the future for compliance with Commission directives. As it now stands, for example, we, our staff, and interested parties, must review three very thick contracts and engage in cumbersome, confusing and time consuming cross-checking. We think consistency would be an enlightened step which, in the long run, will work to everyone's advantage.

VI. RAMPED-UP AND LEVELIZED LONG-TERM ENERGY AND CAPACITY PAYMENT OPTIONS UNDER STANDARD OFFER #4 (OPTIONS #1 AND #2)

Two energy payment options under the standard offer were proposed which warrant separate discussion because they share the same costing methodology, but have different payment streams.

Option #1: Payment stream fixed for 10 years,[2] and follows a ramped-up forecast.

Option #2: Payment stream fixed for 10 years and levelized.[2]

A. Common Elements:

Before addressing the specific differences, (primarily the issue of security), we will describe the common elements.

Contract term: The minimum term is 15 years, and the maximum is 30 years (Utilities should amend their contracts to specify the agreed upon maximum term).

Operation date: The QF project must be on line within 5 years from the date the agreement is executed. However, the QF agrees to the payment stream, based on the forecast, when the contract is signed. This means utilities must have a 15-year forecast when the contract is signed to allow for a maximum 5-year hiatus before operation and payments start after contract execution. QFs can, however, under the negotiated standard offer, make an election within ninety days before production starts on whether they will be paid under the ramped-up or levelized forecast. Thus, while both payment streams are known and fixed when the QF signs a contract, a QF can hold off with its final payment stream election and evaluate its requirements and conditions shortly before production begins.

Forecasts Underlying Contract Prices: The total utility avoided cost underlying the payment streams is technically composed of two elements: (1) avoided shortage costs, related to the peaking capacity the utility can avoid (based on the rental value of a combustion turbine), and; (2) system marginal operating costs, called the "energy" portion of the total avoided cost.[3] The

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[2] Ten years if the contract term is 20 years or more, but ½ of the contract term if the total contract term is less than 20 years.

[3] The appropriate standard for evaluating future utility and QF projects is a forecast of utility's marginal energy cost plus shortage cost. This is only a proxy for a forecast of average marginal composite energy cost and capacity cost. The shortgage cost is not literally the "capacity"

forecasts accompanying the filed standard offers were agreed to at the negotiating conference; while some may think they are too high, and others that they are too low, nevertheless they were agreed to. Whether the forecasts should be revised, for prospective application to new contracts, can be addressed in the subsequent hearings. The following schedules show the forecast energy portion of the total avoided cost for each utility. For illustrative purposes, the table for PG&E shows the price by time of delivery as well as the annual average price, only the annual average prices for Edison and SDG&E are shown:

Pacific Gas and Electric Company
Forecasted Energy Price Schedule

Year of Energy Deliveries	Forecasted Energy Prices*, ¢/kWh						
	Period A (Winter)			Period B (Summer)			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	Annual Average
1983	5.36	5.12	4.94	5.44	5.31	5.19	5.18
1984	5.66	5.40	5.22	5.74	5.61	5.48	5.47
1985	5.75	5.48	5.30	5.83	5.69	5.56	5.55
1986	5.99	5.72	5.52	6.08	5.94	5.80	5.79
1987	6.38	6.08	5.88	6.47	6.32	6.17	6.18
1988	6.94	6.62	6.39	7.03	6.87	6.71	6.70
1989	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1990	8.12	7.74	7.48	8.23	8.04	7.85	7.84
1991	8.64	8.24	7.96	8.75	8.56	8.35	8.34
1992	9.33	8.90	8.60	9.46	9.24	9.02	9.01
1993	10.10	9.63	9.30	10.23	10.00	9.76	9.75
1994	10.91	10.41	10.06	11.06	10.81	10.55	10.54
1995	11.79	11.25	10.87	11.96	11.68	11.40	11.39
1996	12.67	12.09	11.68	12.85	12.56	12.25	12.24
1997	13.61	12.98	12.54	13.79	13.48	13.15	13.14

* These prices are differentiated by the time periods as defined in PG&E's standard offer; the time periods are subject to change in accord with how peak, partial peak, and off peak is defined in

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payment nor is the system marginal operating cost the "energy" cost, but that terminology has evolved into this long-run standard offer proceeding from the short-run standard offer proceedings. This is one complexity among many relating to avoided cost forecasting that will be addressed in the evidentiary hearings.

PG&E's tariff schedules applicable to large industrial customers.

PG&E, Edison, and SDG&E

Forecasted Energy Price Schedule, Annual Average

(¢/kWh)

Year	PG&E	Edison	SDG&E
1983	5.18	5.30	—
1984	5.47	5.60	5.90
1985	5.55	5.70	6.40
1986	5.79	6.00	6.40
1987	6.16	6.40	6.30
1988	6.70	6.90	6.70
1989	7.34	7.60	7.90
1990	7.84	8.10	8.60
1991	8.34	8.60	9.20
1992	9.01	9.30	10.00
1993	9.75	10.10	10.30
1994	10.54	10.90	11.10
1995	11.39	11.80	11.80
1996	12.24	12.60	12.60
1997	13.14	13.60	13.40
1998	—	—	14.20

The preceding schedules show the 15-year forecasts of avoided marginal energy costs, which is, of course, one component of total avoided costs.

In understanding how total contract prices are derived, it is critical to keep in mind there are a number of mix-and-match options for both energy and shortage cost or capacity payments. For example, a QF can elect to sell part of its output under the terms of one of the existing standard offers based on short-run avoided costs; if he did so, the energy sold under short-run as available or firm capacity standard offers, would be subject to price variation, whereas the portion sold under the forecast would have a fixed price. Also, different shortage cost or capacity payment options are available to QFs signing up under any of the energy payment options.

Capacity payment price: QFs may elect to deliver either firm or as-delivered capacity. The QF can select how much firm capacity he will be contracted to provide, and any excess deliveries will receive the as-delivered capacity price. These capacity payments are determined and paid under the same terms as those in existing Standard Offers #1 an #2, for as-available and firm capacity, respectively. Thus, firm capacity payments can be levelized as provided by Standard Offer #2, and are subject to the performance bonus when the QF demonstrates a firm capacity factor in excess of 85%; all capacity payments are made monthly.

The following table shows the annual average capacity payment in ¢/kWh for as-available capacity:

PG&E, Edison and SDG&E

Forecasted Capacity Price Schedule, Annual Average*
(¢kWh)

Year	PG&E	Edison	SDG&E
1983	.798	.799	—
1984	.867	.868	.700
1985	.924	.924	.740
1986	1.004	.993	.800
1987	1.084	1.073	.870
1988	1.164	1.153	.950
1989	1.255	1.244	1.020
1990	1.346	1.335	1.100
1991	1.438	1.439	1.310
1992	1.541	1.690	1.400
1993	1.643	1.804	1.500
1994	1.757	1.929	1.600
1995	1.871	2.055	1.720
1996	2.009	2.215	1.840
1997	2.146	2.352	1.960
1998	—	—	2.100

* For payment purposes the annual average rate will be converted to seasonal ltime [sic] of delivery rates consistent with the Commission approved method applicable to as-available capacity. The annual average rate expressed in ¢/kWh, rather then $/kWh, is developed for the utilities' capacity payment fore-

casts, applying their allocation factors and hours per period currently in use.

B. Forecasted Ramped-Up Payments Based on Energy or System Marginal Operating Costs (Option #1)

Option #1 is the ramped-up payment stream, with the payment varying with season and time of delivery. This provides a direct price signal to encourage peak period delivery by QFs.

During the fixed price period, (maximum 10 years) the QF receives a series of predetermined energy prices for production, broken down by year and costing periods. These fixed prices per kWh are paid regardless of whether the utility's actual avoided costs turn out to be higher or lower. QFs can choose to take a fraction (in 20% increments) of their energy payments under this option, and the remainder under the full short-run avoided costs applicable under Standard Offers #1 and #2. Oil or gas-fired cogeneration facilities are limited to receiving no more than 20% of their energy payments under the forecasted energy price option, with the remainder paid at the full short-run avoided operating costs under other existing standard offers, or under Option #3 (which is described later).

After the fixed price period, (e.g. 10 years) the QF receives payment for energy delivered at the full short-run avoided operating costs which are also paid to QFs under Standard Offers #1 through #3.

This option contains no discounts, requires no security, and has no formula for calculating damages in the event of nonperformance or breach.

C. Levelized Payment (Option #2)

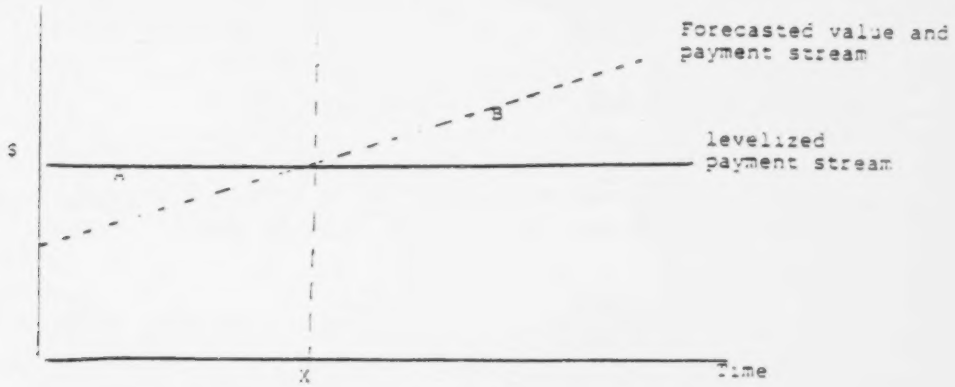
During the fixed price period, the QF will receive prices levelized over that period. The forecast from which these levelized prices are derived is the same as that used in the forecast or ramped-up energy price option. Prices are time-differentiated, and will be paid throughout the fixed price period. This option also does not require any discounts from the utility's avoided cost. However, it does require that the QF post security to protect ratepayers in the event nonperformance occurs and early period

overpayments have been made. And if the utility accepts a lesser grade of security, that may not fully guarantee protection of the ratepayer, then a 1.5% discount from the levelized prices is applied over the fixed price period (specifics concerning security and levelization are discussed below in this section). This option under PG&E's proposed contract, contains a formula for calculating minimum damages in the event of breach; however utilities may also seek to collect foreseeable damages allowed at law for breach of contract, beyond those specified by the formula.

1. Levelization

This is an opportune place to discuss levelization generally, because the distinguishing feature of payment Option #2 is a levelized payment stream.

Levelization is a payment stream where periodic payments are constant over a period of time, and are based on forecasted values and the value of money. It works roughly as follows:



The payor (e.g., utilities and ultimately their ratepayers) applies a discount rate to the ramped-up payment forecast in order to derive an "equivalent" levelized payment stream. As indicated in the above diagram, the result of levelization is that the payor pays a higher level of payments earlier in the time period (area A on diagram) in exchange for lower payments later on (area B on diagram). The payment streams are "equivalent" if, given the payor's opportunities to invest funds (or cost of capital), the savings in the later years (area B) are equivalent to the return that the payor could have earned investing the difference between

the forecasted and levelized payments (area A) early on. The discount rate is that rate of "foregone" compound interest at which the payor is willing to trade for the burden of paying more sooner than would otherwise be the case.

Applied to QF-utility contracts, levelization means the utility will be paying more in the earlier period, and electric rates for consumers in the early period will be incrementally higher as the periodic levelized payments are passed on in the utility's rates. Also, if the QF quits production before the end of the levelization overpayment, (time X on the above diagram), the utility and ratepayers are left having paid more than the commodity was valued. Our concern about levelization stems from these factors. In simplest terms, levelization for QF pricing is a form of ratepayer "loan" to make a perhaps otherwise nonfinanceable QF project viable enough to attract conventional financing. QFs say the option of levelization, which is comparable to ratepayers than their "financing" of utility-owned projects, is only fair. Staff thinks a solid QF project should be financeable if it has a guaranteed price stream, as under Option 1, and that a bank or other investor should make the "loan" needed in early years instead of the ratepayers. But staff agreed to this levelization option on an interim basis to see how effectively it facilitates new QF projects and to see how risky it actually is to ratepayers.

The discount rate negotiated at the conference, to be used in the utilities' levelization calculations, was 15%.[4] If something less than first class security (as discussed later) is put up by the QF to ensure ratepayer recovery for overpayments in the event of nonperformance, an additional 1½% is taken directly off the levelized payment stream to compensate ratepayers for the correspondingly higher risk resulting from a lesser grade of security. There was considerable debate among parties as to the appropriate "opportunity cost of capital" for ratepayers in levelizing payment streams for projects of varying technical and financial risk. If the discount rate used it too high, then ratepayers are not

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[4] PG&E included levelization based payments with both a 13½% and 15% discount rate; however, it shall use 15%, consistent with the agreement reached at the negotiating conference.

fully compensated for the overpayments in the early years of the contract; that is, the levelized payment stream is too high.

Levelization and its attendant problems posed by the use of discounting, security requirements and termination penalties is something which, in a perfect world, we would prefer not to deal with, particularly in the context of a standard offer. We have several concerns about levelization as a feature of even an interim standard offer:

(1) the precedent may lead parties to believe it is the norm;

(2) administering the security provisions of standard offer contracts with levelization can, as the number of QFs increase, be an ongoing administrative chore of some magnitude for utilities (which ultimately translates into additional costs to ratepayers); and

(3) costs to ratepayers from early contract period "overpayment" caused by levelization acerbates the overall level of electric rates, which are now higher than we prefer.

We wonder why a large number of QF projects cannot be financed with the simple forecasted payment stream, which is guaranteed, assuming performance, up to the first ten years of operation. The forecasted ramped-up payment stream offered by the nonlevelization option is a large step forward in terms of payment certainty for QFs, which should greatly assist with financing. The specter of many levelized standard offer contracts concerns us; particularly since we have no evidentiary record that shows solid viable QF projects cannot be developed or financed without levelization.

Our solution is to allow utilities to enter levelized standard offer based contracts for a maximum of one year after the effective date of the [sic] this order. As indicated in the following order, we will address lissues [sic] relating to this payment option as early as possible in evidentiary hearings. And lthis [sic] option may be extended though [sic] a subsequent interim order, if we determine that providing for levelization in a standard offer is in the continuing public interest. Those who represent QFs have the burden of showing why levelization is necessary. Our goal is not to

ensure every possible QG [sic] project and/or technology is financeable; rather, our goal is to provide an economic environment in which solid, well-conceived projects have a reasonable opportunity to be financed through prices paid by utilities and ratepayers. It is not our task to compensate, through standard offer payment terms, for all concerns and reluctance of lenders and equity investors. Ours is a world of risks, and we have no business ensuring that some have little or virtually no risk at the expense of others (i.e., ratepayers). While we will ratify the levelized option for use for one year, one purpose of this discussion is to alert parties directly that we have serious reservations about continuing to provide for levelization in a standard offer.

2. Security Provisions of Levelized Option #2

PG&E very aptly summarizes how the issue of security provisions evolved in the context of the levelization option:

> "This proved to be one of the most troublesome issues in the Settlement Conference. Commission staff wanted QFs to provide very solid, substantive security in order to assure ratepayers would be made whole in the event of termination or nonperformance. QFs wanted the opportunity to substitute lesser security (e.g., liens on their equipment) which is more readily affordable, and to allow utilities to exercise discretion in rejecting any 'inadequate' security that might be offered. Utilities were not anxious to have such discretion within a Standard Offer, because it appeared to present a no-win situation. The QF developer whose proposed security was rejected by the utility could complain that the utility was being unreasonable; if security that the utility accepted eventually turned out to be inadequate, its prudence could be questioned by the Commission.
>
> The result is a compromise. Two tiers of security will be accepted. QFs that provide first class security will be able to avoid price discounts; those that provide lesser security will be subject to a 1.5% energy price discount in the fixed price period. This lesser security—essentially corporate guarantees and equipment liens—is subject to acceptance by the utility. PGandE agreed to this discretionary authority because QFs

> insisted they needed the option of providing lesser security. PGandE reluctantly accepts this discretionary role in this Standard Offer and hopes that in any future recovery proceedings, the Commission will view its exercise of such discretion within the greater context of promoting alternative energy resources." (PG&E's third amended application, pages 15 and 16 of Appendix A).

The higher quality security, the amount of which changes each year as ratepayer exposure is reduced until the levelization mid or crossover point is reached, is any or a combination of the following: A letter of credit, performance bond, paid-up noncancellable project failure insurance or a solid corporate guarantee acceptable to the utility. Lesser security is other security which is acceptable to the utility, such as: a less solidcorporate [sic] guarantee, and liens or a mortgage on the facility and/or the land on which it is located.

Staff believes that if the utilities have discretion to reject second level security, that potential QFs should not be able to appeal the utilities' decision to the Commission. We agree. The ability to provide second level security is a major concession to responsibility of judging it. The utilities should not be second-guessed, and we do not want the responsibility for judging security in individual cases. We expect the evidentiary hearings to develop even clearer security requirements for this standard offer. A standard offer should not have discretionary iterms [sic] in it.

Having utilities administer these security provisions is directly analagous [sic] to their serving in the role as a lender, which in a real sense they are (with the ratepayers' money). We can understand their discomfort in this role, but we think the guidelines are clear enough they can reasonably administer the security provisions. Ultimately, however, we would prefer more concrete security provisions if levelization options are extended, and we expect this issue to be addressed in the evidentiary hearings. directly analogous to their serving in the role as a lender, which in a real sense they are (with the ratepayers' money). We can understand their discomfort in this role, but we think the guidelines are clear enough they can reasonably administer the security provisions. Ultimately, however, we would prefer more concrete security

provisions if levelization options are extended, and we expect this issue to be addressed in the evidentiary hearings. [sic]

D. Curtailment Provisions (Under All Payment Options)

The negotiated curtailment provisions for Standard Offer #4 are utility specific, with PG&E's provisions consisting of the following 2 options:

(a) Curtailment under "negative avoided cost" conditions and a lower "hydro spill rate" under hydro spill conditions with no hourly limit. This option refers directly to this Commission's definition of negative avoided costs and hydro spill conditions.

(b) A limit of 1,000 hours of real time prices per year for negative avoided cost, hydro spill and non-oil/gas units at the margin. This second option requires some further explanation, as PG&E explains:

"PGandE will not curtail the QF when these conditions occur, but will instead offer to continue purchases at a price equal to the current actual avoided energy cost. The QF can then make its own operating decisions; PGandE and ratepayers will be indifferent. PGandE will limit the 1,000 hours to off-peak periods, and increase the price in the other off-peak hours to account for the fact that these low-cost periods are no longer being averaged in.

"PGandE's unique system means it will have to have maximum operating flexibility in the coming years to efficiently utilize the available resources. The 1,000-hour option helps provide this necessary flexibility while remaining faithful to the avoided cost framework. SCE and SDGandE are not providing the opportunity for the QF to remain operational and receive actual avoided costs, but are instead offering annual hourly curtailment limits. PGandE does not believe such an approach is appropriate in its case, and would object to one being imposed". (PG&E's Amended Application, Exhibit A, pages 11-12).

SDG&E's negotiated standard offer includes provisions to curtail QF production for up to a total of 300 off-peak hours per year where such purchases result in "negative avoided cost" to SDG&E "as such term is defined by the CPUC (SDG&E's Amended application, page 22)."

Edison's offer curtails the QFs production for up to 300 off-peak hours when:

> "(i) purchases would result in costs greater than those which Edison would incur if it did not purchase energy from seller but instead utilized an equivalent amount of energy *generated from another Edison source* (emphasis added), or
>
> "(ii) the Edison Electric System demand would require that Edison hydro-energy be spilled to reduce generation". (Edison's Amendment, page 26)[5]

In D.82-01-103, D.82-04-071, and D.82-12-120, we defined "negative avoided costs" as a situation where, due to operational circumstances, purchases from QFs would result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself. We cite such a condition as being when a baseload or large oil-fired intermediate load plant is shut down at night due to an excess of QF electricity but then cannot be restarted and brought up to its rated output for the next day's peak load, thus necessitating instead the start-up of a plant with very high generating costs (e.g., a gas turbine peaker) or an expensive emergency purchase of capacity. In D.82-04-071 the Commission concluded that, while curtailment was not appropriate for hydro spill conditions, a lower "hydro savings" price is appropriate. The decision did not, however, permit a lower price to be established during periods when economy energy is purchased or when avoided costs are positive. Anticipated economy purchases were to be averaged in the avoided cost applied for the entire time period. Proposals to restrict the number of hours that curtailment and hydro spill

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[5] The phrase "generated from another Edison source" is interpreted (by both SCE and the Commission) to exclude economy energy purchases. Hence, it conforms with Commission policy on this issue.

conditions apply were denied in D.82-01-103 and D.82-04-071. However, in D.82-12-120 we directed utilities to undertake studies which would be considered in reviewing future proposals to establish such limits.

Only PG&E's curtailment option a) conforms with our narrowly defined negative avoided cost and hydro spill conditions established for Standard Offers contracts #1 and #2. We acknowledge the nonconformity of PG&E's option b) and the other utilities' curtailment provisions with our previous decisions. However, we consider these disparities as part of the negotiation process and integral to the parties arriving at a negotiated "package". We alert parties that these provisions will be reviewed and evaluated for prospective standard offers in evidentiary hearings.

E. The "Regulatory Authority" Clause

Edison and SDG&E have what are commonly termed "Regulatory Authority" clauses, which allow for changing contract terms if directed by a regulatory agency. Edison's reads as follows:

> "This Contract shall at all times be subject to such changes as any regulatory agency may direct in the exercise of its jurisdiction. If there is any conflict between the provisions of this Contract and any changes directed by such regulatory agency, the Parties shall amend this Contract in a manner consistent with such regulatory changes."

Both utilities indicated they included this clause consistent with prior Commission directives with respect to earlier standard offers. PG&E indicated it was willing to drop this clause because it seems incompatible with a long-term forecast based and binding contract, particularly if this Commission clearly intends to allow utility cost recovery for prices paid under standard offer contracts.

In view of our holding that contracts entered under Standard Offer #4 will not be subject to retroactive change based on prospective developments in the continuing saga of pricing QF power, we think the regulatory authority clause should be deleted. In other words, the quid pro quo for giving QFs certainty with respect to all contract terms, and eliminating the regulatory

authority clause, is that QFs may not freely switch to other contracts later, until their contract term is up, if subsequent contracts or terms appear more favorable. Thus, we are really exchanging certainty of contract sanctity for certainty of commitment, and given our reaffirmation that cost recovery will be allowed utilities for all standard offer power purchase contracts, we think this is only fair. QFs contend that with the regulatory authority clauses in the contracts of Edison and SDG&E there will be insurmountable hesitation by lenders because of uncertainty. In ordering the clauses removed we recognize that we cannot order retroactive changes to interim Standard Offer #4 contracts but, given the restrictions placed on the use and availability of this negotiated standrd [sic] offer, we are willing to commit to that loss in flexibility.

F. SDG&E's Forecast of Marginal Energy Production Costs and Updating Forecasts

SDG&E requests that its 15-year forecast of marginal energy and production costs and its corresponding incremental energy rate be available to price QF power under this standard offer for a maximum of six months after filing its amended application which was filed on July 11, 1983 (SDG&E's amended application, pages 5, 9 and 12).

Near the conclusion of the negotiating conference there was disagreement about the energy rate forecast SDG&E would use in connection with its standard offer. Ultimately, SDG&E filed the forecast most parties thought was agreed to. It did this, according to its amended application, in the spirit of cooperation; however, it indicates its most current forecast is lower (SDG&E's amended application, pages 5-6). Proposing the consensus agreed upon forecast, one SDG&E prepared in March 1983, but requesting a maximum six month period for its availability for QF contracts, was done, according to SDG&E, at ALJ Alderson's suggestion. Our ALJ offered that suggested compromise as a means of avoiding what seemed to be a looming and substantial impasse.

We believe the substance of our ALJ's suggestion has merit. However, rather than impose a hard and fixed time cap for use of

SDG&E's filed forecast, we will direct that it be applied to Standard Offer #4 until further order; and one of the first issues we want considered at the evidentiary hearings, for expeditious consideration and decision, is the reasonableness of SDG&E's forecast, particularly vis-a-vis the level of Edison's and PG&E's. This approach is preferred because we do not want to get into the situation of having a hiatus, where prices based on SDG&E's filed forecast have lapsed, and a forecast to replace it has not been approved. Our solution reasonably addresses SDG&E's concern.

We are not prepared today to address the related questions of the frequency of updating the forecasts of all utilities, and the procedural forum or vehicles for updating. Those are issues, however, that are deserving of all parties' attention during hearings. The forecasts underlying prices in interim Standard Offer #4, for the respective utilities shall, in the meantime, be used as directed in the following order.

VII. FORECASTED INCREMENTAL ENERGY RATE PAYMENTS (OPTION #3)

Capacity payments under this option are the same as those described for Option #1 and #2 (as discussed). However, the energy prices under this option are based on (1) a *forecast* of the utilities' incremental energy rates and, (2) *actual* utility costs for incremental fuel. The incremental energy rate has been referred to by some parties as the derived and/or incremental heat rate, which is incorrect. The incremental energy rate is derived from marginal energy cost forecasts taken from utilities' production simulation models; these models include estimates of the costs of all projected resources at the margin over the term of the forecast. (e.g., 15 years). Once the marginal energy cost forecast is made it is then analyzed to determine the primary fuel for the resource most frequently at the margin, which has turned out thus far to be oil or gas. The overall annual marginal energy cost is then divided by the projected incremental fuel cost for that period to produce, for any given year, a forecast of the incremental energy rate (which is expressed in Btus/kWh). While this is similar to how heat rates are expressed, as derived it does not reflect a system incremental heat rate, because it is derived by only one fuel/resource and not a weighting of all resources that may appear

at the margin at times over the forecast period. For consistency among utilities, and to avoid prolonging confusion, this payment option shall be referred to as the "incremental energy rate" option, and their contract terms and language shall be amended accordingly.

Assuming oil or gas generation is the marginal, incremental, swing generation source, incremental energy costs for utilities are the product of the incremental energy rate and the price paid for oil or gas. This pricing formula and payment stream is most sought by oil and gas cogenerators, as while the forecasted utility incremental energy rate is fixed, the cost of fuel will be actual; and, of course, if the cost of utility oil and natural gas rises or falls there is a direct correlation for the QF's corresponding costs. PG&E likes this payment option because it thinks there is less likelihood, over time, that payments to QFs will deviate from actual realized utility avoided costs (PG&E's amended application, Exhibit H, page 9).

Under PG&E's Option #3[6] the QF will be paid a monthly incremental energy rate, based on a "derived" incremental heat rate forecast and the actual price of marginal fuel (i.e., natural gas or oil). However, there are revisions for making adjustments should PG&E's actual incremental energy rate differ from the projection. The QF, when the contract is signed, can elect a series of annual band widths, expressed in 100s of Btu/kWh, which are equally applied above and below the utilty's [sic] forecast of incremental energy rates. The lower band serves as a floor, and the upper band a ceiling. At the end of each year PG&E determines its actual price of oil and natural gas for its fossil fuel generating plants and divides this weighted cost into the energy payments made to the QF over the year. The result of this calculation is the utility's "actual" (derived) incremental energy rate. If the actual derived heat rate factor for the year is below the elected lower band, PG&E will make a one-time payment so the

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[6] Although PG&E's amended application calls this Option #4, for consistency with the other utility filings, and since PG&E's designated Option #3 is not approved by this decision, we refer to this energy payment Option as #3.

QF receives the value of the lower band for that year; if it falls above the upper limit of the band the QF makes a similar one-time payment to PG&E; finally, if it is within the limits of the band, no payment adjustment is made.

Other than the specifics described above, the contract terms for Option #1 apply to this option. Thus, this option contains no discounts, requires no security and, while probably most attractive to oil and gas cogenerators, is available to all QF technologies. Once the forecast based payment stream ends, the QF will receive the then current avoided energy prices.

PG&E proposes the one-time annual reconciliation adjustment, while Edison would simply compute the price and any adjustment monthly. PG&E explains why it has a different approach as follows:

> "PGandE's heat rate option differs from SCE's in that it contains a single value per year, rather than one for each costing period, and it applies annually rather than monthly. PGandE believes that these differences reflect utility-specific differences and that it would be inappropriate to require PGandE to adopt SCE's approach. Specifically, there appears to be an asymmetry across months for HFRs on PGandE's system. For instance, a typical year could see 2 or 3 months (in the spring) well below the annual fixed HRF, and the remaining 9 or 10 months near or slightly above it. Given a band of the proper width, this could trigger payments to the QF in the spring, with no compensating payments the rest of the year. PGandE could develop a monthly mechanism such as SCE's; however, we believe that a) it would by unnecessarily complex, b) PGandE's structure provides sufficient pricing certainty for QFs, and c) further analysis would be required, and lower HRF [sic] values would likely result." (PG&E's amended application, Exhibit A page 4).

We recognize the benefits of having oil and gas cogenerators on the system to displace the utilities' incremental oil and gas generation units, but only to the extent that: 1) cogeneration results in a more efficient use of fossil fuels (i.e., the cogenerator's

actual incremental energy rate is lower than the utility's) and, 2) California's resource base, no matter how well it can be diversified, may require some oil and gas generation units to meet demand. We are concerned, however, that this energy payment option could, over time, provide incentives to oil and gas cogenerators that are not commensurate with the benefits described above. Whereas Options #1 and #2 place the entire risk that a QF's actual production costs may be higher than our projections of avoided costs, Option #3 removes the risk associated with fuel-price variability from fossil-fuel cogenerators. Instead, ratepayers are exposed to all of the fuel-price variations, which can be very significant for oil and gas. Furthermore, providing a band around the incremental energy rate forecast mitigates some of the potential efficienty [sic] benefits that oil and gas cognerators [sic] can add to the system.

The issue of the utilitities [sic] forecast of incremental energy rates was not resolved at the negotiating conference to the satisfaction of some QFs. At the prehearing conference QFs indicated they found Edison's filed forecast acceptable, while PG&E's and SDG&E's were not. QFs request to reopen the negotiating conference to pursue what, from their perspective, would be a "better" forecast from PG&E and SDG&E. So, at this juncture, we see our choices with respect to payment Option #3 of being the following: 1) To approve Edison's Option #3, and reopen the negotiating conference to consider further the other utilities' forecasts; 2) to put all these forecasts back into the negotiating conference; 3) to allow this payment option, for all utilities, to be taken up in evidentiary hearings and approve nothing today with respect to Option #3 or, 4) to approve the use of Option #3 for all utilities, as filed, on the positive assumption that some QFs may find it useful pending a complete review of Standard Offer #4 and all payment options during evidentiary hearings, during which the feasibility of further negotiations is always an option.

We think the latter approach is by far the most constructive in view of our policy reservations concerning this option and our decision, discussed later, not to reopen the negotiating conference (our reasons for not reopening the negotiating conference are

discussed later). QFs, we note, who are dissatisfied with the incremental energy rate forecasts may compensate to some degree by selecting a wider band around the utility's forecast; thus, while their minimum payments could be lower, their potential maximum payment could be higher. In any event, we find allowing this payment option to go into effect extends to QFs another option and opportunity not now present. Even if only a portion of oil and gas cogenerator QFs can use this option, it is a material improvement over not having the option available. Also, as discussed later, QFs may seek a nonstandard contract if they find Option #3, or any other option or standard offer, does not suit their needs. The continued availability of nonstandard contracts is discussed later in this opinion.

In view of the reservations discussed above, we are limiting the availability of this energy payment option to a maximum of one year after the effective date of the following order. As we determined for payment Option #2, we will not extend that period for payment Option #3 until evidentiary hearings have addressed these issues and we determine that continuing an incremental energy rate option beyond one year is in the public interest.

VIII. UTILITY COST RECOVERY OF PRICES PAID UNDER STANDARD OFFER CONTRACTS WITH QFS

At the negotiating conference the utilities raised concerns about their cost recovery in Energy Cost Adjustment Clause (ECAC) proceedings, assuming we approve the negotiated interim standard offer. They repeat the concern in their amended applications.

We thought it was well understood that prices paid QFs under standard offers approved or mandated by us were per se reasonable for ratemaking purposes. That is one of the hallmarks of the standard offer. It would be inconsistent and unfair for us to approve the use of a standard offer and later question the reasonableness of the prices. While the world may not always be fair, in our regulatory realm this Commission would never subsequently disallow costs necessarily incurred to pay QFs under

standard offer contracts which we expressly found reasonable at the outset.

The only possibility for an ECAC ratemaking adjustment would be if a utility did not diligently enforce all contract provisions which protect the ratepayers. For example, in the event of QF breach or nonperformance, we can easily foresee a ratemaking adjustment if the utility did not take all reasonable measures to collect damages or to have security called on and applied to mitigate a loss; damages and called upon security inure to the ratepayers by a credit to the ECAC balancing account. We would be derelict if we did not ensure utilities remain diligent in administering power purchase contracts on behalf of their ratepayers.

But, with respect to the utilities' greatest concern, we can only say that we cannot envision this Commission, or its successor members, ever being so patently unfair as to attempt to disallow prices paid QFs under Commission approved standard offers.

IX. CONTRACT TERMS OF INTERIM STANDARD OFFER #4 SUBJECT TO RETROACTIVE INCORPORATION RESULTING FROM A.82-03-26 ET AL.

Since the regulatory authority clause of Standard Offer #4 is being eliminated, we must be very specific about any contract terms that are subject to retroactive change. Much of Standard Offer #4 contract language was premised on existing Standard Offers #1 and #2, which will be subject to another order in A.82-03-26 et al. Although Standard Offer #4, as proposed, is very inclusive, there are certain contract terms which should be reasonably consistent with other standard offers; we can direct consistency without changing the substance of negotiated Standard Offer #4. Those contract terms fall in the categories of:

(1) PG&E's line loss factor (PG&E only).

(2) Interconnection procedures and requirements involving lfuture [sic] line and system upgrades.

(3) Right of first refusal and right to purchase on abandonment.

(4) Insurance requirements.

We are aware, however, of the difficulty for some QFs to proceed with their projects without a definite clarification of these final contract terms. We anticipate a decision on A.82-03-26 in the near future. However, for those contracts signed by both parties prior to the effective date of a decision on A.82-03-26 et al. with respect to these terms, we will grant the QF discretion to decide, within 30 days after the effective date of our decision on A.82-03-26, whether or not the terms shall be retroactively changed in his/her contract. In this way, a QF that is ready to proceed immediately following this order will have the definitive contract terms with which to approach financial institutions and the option to have them changed retroactively. However, for any contract signed by both parties after the effective date of our decision on A.82-03-26, we order utilities to amend their respective Standard Office [sic] #4 contract language and terms, for retroactive application, on the above points consistent with the outcome in A.82-03-26 et al. No other terms shall be changed by order of this Commission for retroactive application to executed Standard Offer #4 contracts.

X. OPPORTUNITY FOR NONSTANDARD CONTRACTS BETWEEN UTILITIES AND QFS

During the prehearing conference QFs asked that we address whether utilities may still negotiate nonstandard contracts if proposed Standard Offer #4 goes into effect. Our original direction on this point in D.82-01-103 remains in effect; that is: utilities shall negotiate in good faith with potential QFs who do not want to contract under a standard offer. We expect utilities to continue to abide by that order. We recently addressed and amplified some significant procedural and substantive points relating to nonstandard contract negotiations, which are worth mentioning again for the benefit of all parties (D.83-06-109, in C.83-05-12, *Friant vs PG&E*, pages 4-5):

> "... Utilities were told to negotiate proposed nonstandard contracts in good faith with QFs not wanting to accept a standard offer, but we did not mandate a result. The mandated obligation in terms of end result which utilities do have

is to contract under the applicable adopted standard offers. As long as utilities negotiate in good faith with respect to nonstandard contracts, they fulfill our mandate with respect to those types of contracts. If we allow QFs seeking nonstandard contracts to bring their preferred proposals before us for ratification, instead of utilities applying for approval only after their management thinks a nonstandard contract has merit but wants our ratification in view of cost recovery concerns, the entire negotiating process would take a very different turn from what we envisioned. For then, QFs and utilities would in essence ultimately 'negotiate' with us, and not each other. We refuse to so directly interject ourselves into the arena of QF-utility negotiations. Accordingly, we will not order a 'result' based upon a QF's complaint, but we will impose sanctions on a utility for bad faith negotiations.

"Although the distinction we draw may seem too subtle or without solid basis from Friant's perspective, it is deeply rooted in the role of the regulator vis-a-vis investor-owned public utilities. For ordinarily, in the absence of compelling circumstances, utility management should apply its expertise and judgment within the regulatory parameters we set; we must ensure the parameters are fair and in the overall public interest, but we should not directly 'manage.' By the nature of the relief Friant requests it is asking us to substitute our judgment for that of the utility's management. We will however make a ratemaking adjustment if we find a utility had a lower cost option for power (e.g. QF power) which it did not exercise, or otherwise acted imprudently."

XI. REOPENING THE NEGOTIATING CONFERENCE AND SCHEDULE FOR EVIDENTIARY HEARINGS

QFs want to reopen the negotiating conference to pursue different derived heat rate forecasts from PG&E and SDG&E with respect to payment Option #3, and to develop a fourth payment option.[7] We have decided not to reopen the negotiating

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[7] Early in the negotiating conference PG&E proposed an energy floor price mechanism, which had a fixed price period and a discounting mechanism in later years to compensate for the guaranteed floor price

conference, but as the evidentiary hearing proceeds, we leave it to the assigned Commissioner to determine whether any negotiations regarding Option #3 will contribute to the ultimate decision affecting the future of Option #3 beyond the one-year period provided by this order.

When we announced the settlement conference we stated it would run for four weeks. Our ALJ allowed it to go for five weeks. We knew at the outset some parties, at the conclusion of the negotiating conference, would probably either be dissatisfied with the results or want it to go longer if not everything was "settled". That's the essence of a negotiating session; there are inherent frustrations built into that process.

The negotiating conference required a lot of staff expertise and the participation of our Utilities Division director. Five weeks is enough. Also, a negotiating conference should be held for only the period specified at the outset, otherwise parties will, for good reason, have the expectation that if they do not like the results the conference can go on and on until they do. And there is always the real, but undesirable, possibility of Parkinson's Third Law starting to apply when we hold negotiating conferences, which, in

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during the fixed price period. Then, very late in the negotiating conference, a variation was proposed by U. S. Windpower, but was not developed to the point of the various parties (utilities, staff and QFs) being able to reach a consensus. Of the three utilities, only PG&E developed this payment option in the amended applications. Edison and SDG&E, as our staff, think the concept may hold some promise but that it needs considerable study. Whereas all the other payment options have prices that are based either completely or substantially on a fixed forecast, PG&E's proposed floor price mechanism makes payments to QFs, over time, based on actual utility avoided costs. However, in the early years of the contract the prices can set as a floor which can be *above* the levelized payment stream prices in Option #2; there is a long payback period provided for in later years if early year payments substantially exceed actual avoided costs. The payback period, depending on the contract term and amount of overpayment, can by substantially longer than the payback period in Option #2. Thus, despite discounting factors in later years, the issue of risk assessment and security provisions become even more critical for this proposed payment option than Option #2.

essence, is: work always fills the time allowed for it. Another aspect of reopening the negotiating conference for the specific purposes proposed by QFs is that it would tend to be taken by all parties that we strongly expect a certain result (e.g., that SDG&E and PG&E should raise their derived incremental energy rate (forecast), or that we conceptually embrace a payment option, such as the floor price mechanism. We have no reason to believe any of the energy rate forecasts are too low (or for that matter too high), or that the floor price mechanism payment option has conceptual merit. Taking the extraordinary step of ordering negotiations reopened under these circumstances would not do justice to the concept of allowing parties a fixed time to reach a negotiated consensus. As this is our first experience with a negotiating conference in a generic and complex proceeding, and substantial results have already been accomplished, we do not think it is either necessary or desirable to reopen it. We are sorry if some are disappointed by our decision on this point, but as we said earlier, that's the negotiating process.

We would have been surprised had some not been disappointed. At this juncture we think it is most constructive for parties to spend their time to start preparing themselves for evidentiary hearings, so their prepared showings are complete and well developed. They are free, in doing this, to exchange ideas and concepts.

To ameloriate some frustration, disappointment, and possible economic forebearance, we are, as discussed above, authorizing the incremental energy rate payment Option #3 for all three utilities, and not just Edison, so that option is extended throughout most of the state.

All parties must realize that while we are approving the negotiated standard offer, they should not assume the methodology underlying the derived prices and the contract terms have significant precedential value in our continuing process of adopting a standard based on long-run avoided costs. When evidentiary hearings begin, parties should be prepared to examine and address all the concepts embodied in the negotiated standard offer.

When should evidentiary hearings begin? Some parties, as discussed above, are extremely anxious for hearings to start almost immediately; the utilities would prefer a pause, in essence to catch their breath and gain some experience with the negotiated standard offer. While we are anxious to proceed with our continuing and evolving endeavor of valuing and pricing QF power, and establishing a lasting standard offer based on long-run avoided costs, we think it would be very useful for the parties to digest, evaluate, and reflect on what has been done thus far in preparing for hearings. Hearings, we believe, should start in early 1984, with another prehearing conference in December of 1983. The prehearing conference will be set by a separate notice.

XII. EFFECTIVE DATE OF THIS OPINION AND ORDER

We think that Standard Offer #4 and its three payment options, which are approved and adopted by this opinion and the following order, are a significant step toward valuing and pricing QF power over the long term. QFs have gained some more standard offer options, which can only help stimulate new projects and facilities.

Given the consensus reached, we do not anticipate receiving applications for rehearing on this interim decision. Accordingly, we will make the following order effective the date of signature. We also do this because we think it is in the public interest to have Standard Offer #4, albeit a negotiated and interim standard offer, available for use as soon as possible. However, it is possible that applications for rehearing may be filed within the time period after the order's effective date as set out in Public Utilities Code § 1731, and we expect utilities not to actually enter or sign contracts under Standard Offer #4 for at least 30 days after today, and until any such applications for rehearing, if they are filed, are acted on by us. We take this measure as a procedural safeguard, in fairness to all parties, in view of our acting without an evidentiary record upon which to make findings of fact sufficient to issue a decision to withstand judicial review.

XIII. FINDINGS OF FACT AND CONCLUSION OF LAW

Findings of Fact

1. D.83-05-038 announced a negotiating conference for these consolidated proceedings. That conference was publicly noticed, open to the public, and lasted from May 23 through June 24, 1983.

2. The amended applications in these proceedings, with the changes noted on the record during the second prehearing conference, contain Standard Offer #4. That standard offer, and three payment options under it, are acceptable to the respective utilities, QFs, and staff, for interim use.

Conclusion of Law

The standard offers filed by the applicant utilities should be ratified for use by utilities and QFs in contractual power purchases, as authorized and restricted by the following order.

INTERIM ORDER

IT IS ORDERED that:

1. Standard Offer #4, Payment Options #1 through #3, as proposed by the Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), and Southern California Edison Company (Edison), shall be used by those utilities until further order of this Commission, but, in any event, for a minimum of six months and for a maximum of two years after the effective date of this order. However, in exercising those payment options under Standard Offer #4 the following restrictions or conditions shall apply:

   a. Qualifying facilities (QFs) who are under a power purchase contract with a utility, either a contract under a standard offer or a nonstandard contract, shall not enter a contract based on Standard Offer #4 until their existing contract term is up.

b. Only QFs who are not under contract and who have not completed their facility as of the effective date of this order may elect Payment Option #2.

c. The "regulatory authority" clause in SDG&E's and Edison's Standard Offer #4 shall be eliminated.

d. QFs who enter contracts under Standard Offer #4 will not be allowed to switch to a subsequent version of Standard Offer #4, or to other standard or nonstandard contracts, until the term of their contract is up.

e. Payment Options #2 and #3 shall be extended and exercised by utilities for a maximum period of one year after the effective date of this order.

f. The terms in Standard Offer #4, Options #4, Options #1, through #3, are subject to change and retroactive application in contracts signed by both parties after the effective date of a decision in A.82-03-26 et al., and depending on the outcome in that proceeding, with respect to:

1. PG&E's line loss factor.

2. Interconnection provisions involving future lines and system upgrades.

3 Insurance.

4. Right to first refusal and right to purchase and abandonment.

For contracts signed by both parties (QF and utility) prior to the effective date of a decision on the above terms in A.82-03-26 et al. the QF has the option of deciding to keep the terms as set forth in the signed contract if the QF notifies the utility of this decision in writing within 30 days after the effective date of the Commission decision on A.82-03-26.

g. PG&E shall use a 15% discount rate for its levelized payment stream under Option #2.

Any other ordered changes to Standard Offer #4 will be for prospective application only in new contracts.

2. A QF which enters a contract under Standard Offer #4, as approved by this order, may not switch to another contract until the term of its Standard Offer #4 contract has expired or it has terminated; if a QF terminates early by breaching the contract the utility is under no obligation to enter a new contract or to purchase the QF's power until: (1) minimum damages are paid if a minimum damages clause in the contract is applicable; or (2) if there is no applicable minimum damages clause, until foreseeable damages have been paid to the utility. The payment of minimal damages shall not discharge the breaching QF from ultimate payment of foreseeable damages caused by the breach. Utilities, on behalf of their ratepayers, shall vigorously pursue recovery of all foreseeable damages in the event of a QF breaching a power purchase contract.

3. Prices paid to QFs for power purchased under Standard Offer #4 provisions, and contracts as under any standard offer, will be recovered through the ECAC balancing account, and any collection the utilities make with respect to recovering for damages or called on security shall be credited to that balancing account. However, utilities will be subject to ECAC ratemaking adjustment if it is demonstrated they did not diligently enforce all contract provisions.

4. Another prehearing conference shall be scheduled and held before evidentiary hearings begin. Its purpose will be to determine the order in which issues shall be addressed, dates for exchanging prepared testimony, and to set hearing dates. The issues that shall be addressed as early as possible in evidentiary hearings, and which we may address by another interim order, are:

a. SDG&E's forecast of energy production costs.

b. Whether the levelized energy payment and the incremental energy rate payment options should be extended for Standard Offer #4 beyond the one year period as ordered above.

5. PG&E, SDG&E, and Edison shall confer among themselves and with our staff to devise uniform Standard Offer #4 contract language, except for the very few terms which must be utility specific due to different operating characteristics. They

shall jointly submit their proposed uniform contract language as a compliance filing in these proceedings within six months from today (making the filing with the Docket Office and serving all appearances). Their proposed uniform contract language shall not be effective or used in contracts until it has been approved by this Commission.

This order is effective today.

Dated September 7, 1983, at San Francisco, California.

I abstain.

/s/ PRISCILLA C. GREW
Commissioner

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
Commissioners

Commissioner William T. Bagley, being necessarily absent, did not participate.

APPENDIX A
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List of Appearances

Applicants: *Larry C. Mount,* Attorney at Law, for Southern California Edison Company; *Wayne P. Sakarias,* John R. Asmus, Jr., and Vincent D. Bartolomucci, Attorneys at Law, for San Diego Gas & Electric Company; and Charles W. Thissell and *Jo Ann Shaffer,* Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: *Roy Alper,* Attorney at Law, for Independent Power Corporation; Chickering & Gregory, by *C. Hayden Ames,* Attorney at Law, for Geothermal Generation, Inc.; Pillsbury, Madison & Sutro, by *Michael R. Barr,* Attorney at Law, for Pillsbury, Madison & Sutro; Hanna & Morton, by *R. Lee Roberts,* Attorney at Law, and Henwood Associates, Inc., by David Branchcomb, for Ultra Systems, Inc., and Occidental Geothermal, Inc.; *Donald C. Davis,* for Herzog Contracting Corporation; *Nicole A. Clay,* for San Diego Energy Recovery Project (SANDER); *Frank F. Duquette,* for McDonnell Douglas; *Joseph Egan,* for University Energy; *Paul H. Eichenberger,* for SAI Engineers, Inc.; *Mark R. Farman,* for Resource Management International, Inc.; *Michel Peter Florio,* Attorney at Law, Jon Elliott, and Sylvia Siegel, for Toward Utility Rate Normalization (TURN); Lee Freeman, *Douglas Porter,* and Jon Castor, Attorneys at Law, for Pacific Lighting Energy Systems; *Janice G. Hamrin,* and Dan Richard, Attorney at Law, for Independent Energy Producers Association; *Richard C. Hill,* for Tosco Corporation; Nossaman, Guthner, Knox & Elliott, by *Peter C. Hoffman,* Attorney at Law, for Applied Power Technology, Inc.; *Neal A. Johnson,* for California Solid Waste Management Board; *Jim Kaiser,* for Sierra Energy and Risk Assessment; *Laura B. King,* for Natural Resource Defense Council; *Jane S. Kumin,* for Natomas Company; *C. M. Laffoon,* for Geothermal Generators, Inc.; *Mark Lyons,* Attorney at Law (New York, Washington, D.C.), for Ultra Systems, Inc.; P. R. Mann & Associates, by *Philip R. Mann,* Attorney at Law, for California Manufacturers Association; *William B. Marcus,* for California Hydro Systems, Inc.; *Kenneth R. Meyer,* for Energy Consulting Group; *Martin C.*

Recchuite and Michael J. Myers, Attorney at Law, for ARCO Solar, Inc.; Brown, Vence & Associates, by *Tom Reilly,* for Brown, Vence & Associates; *Donn Ruotolo,* for Ebasco Services, Inc.; *James Samis,* for Thermonetics, Inc.; *Gary D. Simon,* for Sigma Group; Graham & James, by *James D. Squeri,* Attorney at Law, for Union Oil Company of California; Messrs. Downey, Brand, Seymour & Rohwer, by *Philip A. Stohn,* Attorney at Law, for Federal Paper Board, Inc., and Sutherland, Asbill and Brennan, Attorneys at Law; William E. Swanson and *Jasper Williams,* Attorney at Law, for Stanford University; *Randall M. Tinkerman,* for American Energy Projects, Inc.; *Frederick S. Waiss,* Attorney at Law, for Stauffer Chemical Company; *Gregg Wheatland* and Kathy Weinheimer, Attorneys at Law, for California Energy Commission; Cooper Engineers, by *Mark White,* for West County Agency; *Harry Winters,* for University of California; *Matthew J. Wristbridge,* Attorney at Law, for General Electric Company; *Donald G. Salow,* for Stone & Webster; *Margaret E. Rueger,* for U. S. Windpower, Inc.; and *Reed V. Schmidt* and *Norman Ross Burgess,* for themselves.

Commission Staff: *Brian T. Cragg,* Attorney at Law, and *John D. Quinley.*

(END OF APPENDIX A)

APPENDIX C

Decision 83-12-050 December 20, 1983
Before the Public Utilities Commission
of the State of California

Application 82-04-44
(Filed April 21, 1982; amended April 28, 1982,
July 19, 1982, July 11, 1983, and August 2, 1983)

Application 82-04-46
(Filed April 21, 1982; amended May 12, 1982,
July 11, 1983, and August 10, 1983)

Application 82-04-47
(Filed April 21, 1982; amended
July 11 and August 2, 1983)

Second Application of Pacific Gas and Electric Company
for Approval of Certain Standard Offers Pursuant
to Decision No. 82-01-103 in Order Instituting
Rulemaking No. 2.

And Related Matters.

(See Decision 83-09-054 for Appearances.)

OPINION ON PETITIONS FOR MODIFICATION OF DECISION 83-09-054

On September 7, 1983 we issued Decision (D.) 83-09-054, which was an interim decision, adopting three payment options for Standard Offer No. 4. These options are to be used by the three applicant utilities in these consolidated proceedings. Our decision followed after a five-week negotiating conference and, subsequently, a prehearing conference lasting two days.

Petitions for modification were filed by the Independent Energy Producers (IEP) and Occidental Geothermal, Inc. (Occidental); a response to both petitions was filed by Southern California Edison Company (Edison), and IEP responded to Occidental's petition.

Occidental's Petition

Occidental points out that our D.83-09-054 directed the utilities to delete the regulatory authority clause, but that Edison's contract contains another clause, termed the "amendment clause" which Occidental thinks could have substantially the same effect as the regulatory authority clause that was deleted. We ordered the regulatory authority clause deleted to afford qualifying facilities (QF) the certainty and sanctity of contract terms and fixed term prices they wanted, but in exchange we did not allow subsequent contract switching. The regulatory authority clause, of course, could have allowed us to essentially change contract terms retroactively. Edison's response is that although the "amendment clause" would apply only if both Edison and the QF agreed that there was a "change in circumstances" necessitating a change in the contract terms, it does not object to removing the clause if keeping it in the contract alarms QFs. We will direct Edison to remove the amendment clause from its Standard Offer No. 4.

The second point raised by Occidental is that Edison's Standard Offer No. 4 is not clear that after the fixed price term or prior to the time of firm delivery, the QF will receive energy payments based on Edison's full avoided operating cost as determined now for Standard Offer No. 2 (for firm delivery based on short-run avoided cost). Edison's response on this point is essentially that it did not mean to build any ambiguity into the contract. It agrees to change the relevant contract provisions by inserting the language underlined below (see Attachment A-7 to Edison's response):

> Seller shall be paid a Monthly Energy Payment for Energy delivered by Seller and purchased by Edison at a rate equal to 100% of Edison's published avoided cost of energy <u>based on Edison's full avoided operating cost as updated periodically and</u> accepted by the Commission.

We think the amended contract language proposed by Edison in its response to Occidental's petition is clear enough. Occidental's expressed fear is that a future Commission may decide that QFs should be paid 80% of utilities' full operating costs, and that,

instead of 100%, only 80% would be paid by Edison. With Edison's proposed amendment all the Standard Offer No. 4 contracts refer to "full avoided operating cost." Because the fixed term is 10 years, it is extremely difficult to estimate what short-run avoided costs will be after that period. But it is clear QFs under Standard Offer No. 4 contracts will receive 100% of full avoided cost as those costs are then determined and accepted by this Commission. That is all the certainty contemplated at the negotiating conference, and it is all the certainty we can extend at this time.

Furthermore, on November 16, 1983, Occidental responded to Edison's response by applauding "Edison's good faith in making these important modifications." Occidental therefore seeks to withdraw its petition. IEP, similarly seeks dismissal of that portion of its petition supporting Occidental's petition. We will direct Edison to amend its contract language as proposed. No further amendment is necessary or appropriate.

IEP's Petition

IEP, in addition to supporting the points addressed by Occidental, takes exception to the procedure we set out in D.83-09-054 to initiate the process of having a standardized Standard Offer No. 4. We ordered the three utilities and our staff to work together to develop standard contract language, with the resulting proposed contract to be reviewed in subsequent hearings. While pleased with our effort for more standardization, IEP thinks QFs will be unfairly prejudiced by not being part of all meetings on the subject between the utilities and our staff.

We adopted the procedure because we thought it could expedite at least getting a work product for the many and various QF interests that are parties to these proceedings to review and react to. We thought the initial logistics for the undertaking, which is a complex task, would be more expedient: The many QF representatives will have full opportunity to review the work product filed by the utilities. Rather than modify the procedure, we suggest that our staff arrange an informal meeting with the utilities and QFs shortly after the utilities file the proposed standard language, which will be served on all parties. Thereafter, any remaining

concerns and issues can be more succinctly addressed during hearings. We will not modify the procedure as requested by IEP. We will, however, order the utilities to file the standard contract language six months from today.

Conclusion

Standard Offer No. 4, along with the energy price, incremental energy rate and shortage value forecasts adopted by D.83-09-054 has become effective. New incremental energy rates and/or avoided capacity cost values that may be adopted by the Commission in general rate case or ECAC proceedings will not affect the price forecasts established over the fixed payment term under Standard Offer No. 4, until further orders are issued in this proceeding.

No applications for rehearing were filed after D.83-09-054 was issued. We trust there will be no further petitions for modification of that decision, as parties should raise any concerns or proposals relating to Standard Offer No. 4 at the upcoming evidentiary hearing. We will be very reluctant to indulge any petitions that may address or propose piecemeal changes to existing Standard Offer No. 4, because it is being relied on by QFs and utilities alike. Efforts for ex parte modification only cloud an overall endeavor to bring some clarity and certainty so that the QF industry can analyze the standard offers available and make its choices. Procedurally, the next step for parties interested in this standard offer, and any changes for prospective application is to raise these points in the evidentiary hearings.

Findings of Fact

1. The modifications Edison proposes for its Standard Offer No. 4 contract, contained in its response to IEP's and Occidental's petition, are reasonable and should be adopted.

2. QFs are not unduly prejudiced or denied due process by the procedure D.83-09-054 established to have uniform standard contract language proposed.

Conclusions of Law

1. The petition for modification filed by Occidental should be granted, while IEP's petition should be granted in part and denied in part in accordance with our findings in this order.

2. The following order should be effective today to bring certainty quickly and enable QFs and others to expeditiously evaluate contract options.

ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) shall amend its Standard Offer No. 4 as it proposes in its response to the petitions for modification filed by the Independent Energy Producers (IEP) and Occidental Geothermal, Inc. (Occidental).

2. The petition for modification of Occidental is granted with respect to Edison's removing the "amendment clause" of its Standard Offer No. 4 contract, and it is granted to the extent of Edison's proposed modifications with respect to the energy price to be paid either before firm production or after the fixed price term.

3. IEP's petition for modification is granted with respect to Edison's being ordered to delete its amendment clause, but denied concerning its proposed modification of the procedure in Ordering Paragraph 5 of D.83-09-054.

4. The compliance filing ordered by Ordering Paragraph 5 of D.83-09-054 shall be filed no later than six months from today.

This order is effective today.

Dated December 20, 1983, at San Francisco, California.

I abstain because of reportable financial interest in potential small power producers.

/s/ PRISCILLA C. GREW
Commissioner

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
WILLIAM T. BAGLEY
Commissioners

APPENDIX D

Decision 84-08-035 August 1, 1984

Before the Public Utilities Commission
of the State of California

Application 82-04-44
(Filed April 21, 1982;
amended April 28, 1982,
July 19, 1982, July 11, 1983
and August 2, 1983)

Application 82-04-46
(Filed April 21, 1982;
amended May 12, 1982,
July 11, 1983, and
August 10, 1983)

Application 82-04-47
(Filed April 21, 1982;
amended July 11, 1983
and August 2, 1983)

Second Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Instituting Rulemaking No. 2. And Related Matters.

OPINION MODIFYING DECISION 83-09-054

By Ordering Paragraph 1 of Decision (D.) 83-09-054, this Commission ordered that "Standard Offer No. 4, Payment Options Nos. 1 through 3, as proposed by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) shall be used by those utilities until further order of this Commission, but, in any event, for a minimum of six months and for a maximum of two years after the effective date of this order." With respect to Payment Options Nos. 2 and 3, the utilities were to exercise these options for a maximum period of one year after the effective date of the order. Because D.83-09-054 became

effective on September 7, 1983, these payment options are due to expire on September 7, 1984.

Standard Offer No. 4 was the result of a negotiating conference held during the summer of 1983. The goal of the negotiating conference was to develop an interim Standard Offer No. 4 which the parties "could comfortably tolerate and work under while refinement and 'perfection' could be pursued in subsequent evidentiary hearings." (D.83-09-054, at p. 8.)

By Administrative Law Judge's (ALJ) Rulings issued during 1984, the procedure to be followed in these "subsequent evidentiary hearings" was established. The proceeding has been divided into two phases—Phase I which will focus on the appropriate costing methodology for Standard Offer No. 4 and Phase II which will examine the prices based on the adopted methodology, appropriate price approaches, and all other terms of Standard Offer No. 4. Hearings for Phase I began on July 23, 1984.

On May 7, 1984, the Commission staff filed a "Recommendation of the Commission Staff to Establish Procedures for Phase I of the Long-Run Offer Hearings." Among other things, the staff observed that because Phase I was limited to an examination of costing methodologies, it would be appropriate to defer issues related to payment options until Phase II as directed by the ALJ. Under these circumstances, it is the staff's opinion that energy Payment Options Nos. 1, 2, and 3 and the energy price forecasts adopted in D.83-09-054 be extended until the conclusion of Phase II. The staff asserts that this approach will preserve the status quo, enabling qualifying facilities (QFs) to have the benefit of energy price certainty and eliminating any need to analyze and adopt incremental energy rates prior to Phase II.

During the prehearing conference of May 9, 1984, the staff reiterated these recommendations. While there were no objections to the recommendations, at least one party requested that the incremental energy rate to be paid the QF by PG&E under Option No. 3 be based on the incremental energy rate approved in PG&E's most recent general rate case.

On June 15, 1984, Independent energy Producers (IEP) filed a motion for a revised procedural schedule for the Standard Offer

No. 4 proceeding. Specifically, IEP requests that (1) interim Standard Offer No. 4, Payment Options 1, 2, and 3 be continued through the end of 1986 or until the issuance of a final decision in this proceeding; (2) hearings on the "costing methodology" be commenced as scheduled by the ALJ; (3) hearings on a revised incremental energy rate be commenced no later than October 1984; and (4) hearings "on the broader assumptions and terms of a final Standard Offer No. 4" be commenced after the Commission issues its decisions on costing methodology and an interim incremental energy rate pricing option. According to IEP, the incremental energy rate used for purposes of interim Standard Offer No. 4 is not a viable option for gas-cogenerated QFs.

IEP's motion is supported by the Independent Power Corporation (IPC). IPC further asks that PG&E's SDG&E's and SCE's interim Standard Offer No. 4 incremental energy rates be modified to reflect information developed in their most recent general rate cases.

WE have reviewed these comments and concur with the staff, IEP, and IPC regarding the extension of negotiated Standard Offer No. 4. At the time we issued D.83-09-054 we contemplated that the issues related to the payment options would have been explored in evidentiary hearings prior to the expiration date set for Payment Options Nos. 2 and 3. In fact, we optimistically forecast the conclusion of these hearings as early as six months from the issuance of D.83-09-054. Unfortunately, only hearings on Phase I of this proceeding will be concluded prior to September of this year, with Phase II commencing after that time.

Under these circumstances, and given the general acceptance of interim Standard Offer No. 4, we will extend the effective date of the terms of that offer, including Payment Options Nos. 1, 2, and 3, and the energy price forecasts adopted in D.83-09-054. This extension, which applies to all terms of the offer, will be effective until further order of this Commission.

We will not, however, amend Payment Option No. 3 in any way. That payment option was part of the negotiated package which the Commission approved on D.83-09-054. A change in one term would require the reexamination of all other terms of the

standard offer. We prefer to maintain the status quo and adopt modifications to Standard Offer No. 4 following the evidentiary hearings now scheduled in this proceeding. We also note that a QF who finds the terms of interim Standard Offer No. 4 unacceptable may in fact negotiate a separate contract. Despite some QFs dissatisfaction with that remedy, we have made clear in previous decisions that all utilities are to negotiate with QFs in good faith.

With respect to the requests for October hearings on the utilities' incremental energy rates, we are unable to commit our limited resources to such hearing dates at this time. At the most, we can reiterate that hearings on Phase I began on July 23, 1984. Upon completion of that phase, the Commission will make a determination either in its decision in Phase I or by ALJ Ruling whether to segregate the issue of incremental energy rate valuation and hear the matter prior to Phase II hearings.

Findings of Fact

1. A reasonable modification of D.83-09-054 has been requested by the Commission staff, IEP, and IPC to extend the effective date of interim Standard Offer No. 4.

2. The other requested modifications of the Standard Offer No. 4 procedural schedule cannot be adopted at this time.

Conclusions of Law

1. The terms of interim Standard Offer No. 4 approved in D.83-09-054 should be extended until further order of this Commission.

2. The motion of IEP should be denied, except to the extent granted in keeping with Conclusion of Law 1.

3. To ensure the extension of Standard Offer No. 4 before it would otherwise expire, this order should be made effective today.

ORDER

IT IS ORDERED that:

1. All terms and conditions of interim Standard Offer No. 4 adopted in D.83-09-054 shall be extended until further order of this Commission.

2. The motion of Independent Energy Producers, except to the extent granted by Ordering Paragraph 1, is denied.

This order is effective today.

Dated August 1, 1984, at San Francisco, California.

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
Commissioners

Commissioner Priscilla C. Grew, being necessarily absent, did not participate.

Commissioner William T. Bagley, being necessarily absent, did not participate.

APPENDIX E

Decision 85-04-075 April 17, 1985

Before the Public Utilities Commission of the State of California

Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983 and August 2, 1983)

Application 82-04-46 (Filed April 21, 1982; amended May 12, 1982, July 11, 1983, and August 10, 1983)

Application 82-04-47 (Filed April 21, 1982; amended July 11, 1983 and August 2, 1983

Second Application of PACIFIC GAS AND ELECTRIC COMPANY for Approval of Certain Standard Offers Pursuant to Decision No. 82-01-103 in Order Ins ituting Rulemaking No. 2

And Related Matters.

INTERIM OPINION

I. Summary

This decision continues the suspension of Payment Option No. 3 of interim Standard Offer (SO) 4 for Qualifying Facility (QF) projects over 50 megawatts (MW), which had been ordered earlier for Pacific Gas and Electric Company (PG&E) and Southern California Edison (SCE). It also extends the suspension for projects over 50 MW to Payment Option No. 3 of interim SO 4 for San Diego Gas and Electric Company (SDG&E). It presents two options for comment regarding continued availability and terms of all of Payment Option No. 1 and Payment Option No. 2, and of Payment Option No. 3 for projects less than 50 MW, prior to availability of a final long-run standard offer.

In assessing whether the existing standard offers continue to provide a reasonable protection for ratepayers, we have relied primarily on the utility filings of the results of project information questionnaires sent to QFs as part of our adopted Interconnection Priority Procedure (IPP), and on the information contained in

the utilities' most recent Quarterly Status Reports (QSRs) containing data current through the end of 1984. We conclude that the capacity payments in the interim SO 4 and the energy payments in Payment Option No. 1 and Payment Option No. 2 of the interim SO 4 would over-value additional QF projects not already under contract to the utilities. This is true for all sizes of QF projects and for SDG&E as well as for PG&E and SCE.

The Public Staff has recommended an immediate suspension of all payment options of interim SO 4 for PG&E and SCE until a final SO 4 is available, unless prices are adjusted to reflect current conditions. We agree with Public Staff that further study is needed of the implications of large cogeneration projects over 50 MW for utility resource planning purposes. Because of the potentially large impact of such projects on system avoided costs, we prefer that they not be allowed to sign Payment Option No. 3 until we understand more fully the utilities' long-run costs avoided by such projects as part of Phase II of the current long-run pricing proceeding.

Such caution does not appear warranted for other projects, however. Because of our continued wish to encourage cost-effective QF development, and because of the continued uncertainty regarding how many signed QFs will actually complete their projects and operate successfully, we are reluctant to suspend interim SO 4 entirely. At the same time, because of our desire to not delay further the development of a final SO 4, we see only one other realistic approach to providing for the protection of ratepayers at this time: that is for us to modify the interim SO 4 prices offered to new QFs which have not yet signed contracts to a level which reflects the value of additional QF projects more realistically. This action would maintain the availability of interim SO 4 contracts for most projects while final SO 4 terms are being developed, yet not unduly delay the final SO 4 proceedings.

With this in mind we present a method for adjusting the capacity payments in PG&E's and SCE's interim SO 4 contracts, based on calculations provided by our staff at the request of the assigned Commissioner, and detailed in Appendix A. The capacity payments in SDG&E's interim SO 4 would be modified to those adopted for its SO 1 and SO 2 in its most recent general

rate case. We also propose that the energy payments in payment Option No. 1 and Payment Option No. 2 be reduced by 10 percent, but conclude that no adjustment to the incremental energy rates in Payment Option No. 3 for projects under 50 MW is warranted at this time.

The revised interim SO 4 contracts would be in effect for each utility only until a set amount of new QF capacity enters into contracts, standard or non-standard, with the utility. That amount is 1,250 MW for each of PG&E and SCE and 200 MW for SDG&E, counted from April 17, 1985. At that point, all of interim SO 4 would be suspended for that utility until a final long-run standard offer becomes available. Projects signing revised interim SO 4 contracts would have to comply with the milestones adopted in our Interconnection Priority Procedure.

We provide for a workshop on May 3, 1985, in which staff will be available to answer any questions parties may have regarding the calculations underlying the capacity adjustment, and for parties to file written comments by May 10, 1985, stating whether they prefer complete suspension of interim SO 4 or implementation of the capacity and energy payments presented in this decision. Based on the filed comments, we plan to choose between the two approaches by June 5, 1985.

To prevent a "gold rush" of projects wanting to sign the current interim SO 4, we suspend all payment options of interim SO 4, effective immediately, pending further Commission action.

II. Background

We first authorized what is termed interim Standard Offer 4 in September 1983, by Decision (D.) 83-09-054. The three payment options under SO 4 resulted from a negotiating conference among the parties, held at our direction. A final SO 4 based on the utilities' long run avoided costs is being developed through evidentiary hearings. However, there was substantial agtreement among utilities, QFs, and our staff that such an interim solution should be in effect until the final SO 4 becomes available. Briefly, the three payment options are as follows:

Payment Option No. 1 provides increasing energy payments which are set for the first 10 years of the contract at the time the contract is signed. Oil or gas-fired cogenerators are allowed to receive only 20 percent of their energy payments under Option 1.

Payment Option No. 2 provides fixed, levelized energy payments based on Option 1 forecasts of energy prices, for the first 10 years of the contract. Since energy payments in the early years are larger than their value to the utility, QFs must post security and must pay damages if they do not perform for the duration of the levelization period. Oil or gas-fired cogenerators cannot sign Option 2 contracts.

Payment Option No. 3 provides "incremental energy rates" which are fixed at the time the contract is signed, for up to 10 years. The QF receives energy payments which are the incremental energy rates times the gas (or oil, if it is the marginal fuel) price at which the utility buys fuel for its own generation facilities. For PG&E, the QF can select a band width around the forecast incremental energy rates, and will receive payments based on the floor or ceiling of the band width if PG&E's realized incremental energy rates are outside the band width.

For any of the three payment options, QFs may elect to deliver either firm or as-delivered capacity, with capacity payments equal to those in effect for SO 1 or SO 2 at the time of the negotiating conference, for as-available or firm capacity respectively.

While all the parties participating in the negotiating conference were in general agreement regarding the reasonableness of Payment Option No. 1 and Payment Option No. 2, the issue of the utilities' forecast of incremental energy rates was not resolved at the negotiating conference to the satisfaction of some QFs. QFs indicated that they found SCE's filed Payment Option No. 3 acceptable while PG&E's and SDG&E's were not, and requested that the negotiating conference be reopened to pursue what, form their perspective, would be a "better" forecast from PG&E and SDG&E.

In D.83-09-054 we declined to reopen the negotiating conference, and approved the terms of Payment Option No. 3 as filed by PG&E andSDG&E, "on the positive assumption that some QFs may find it useful pending a complete review of Standard Offer #4 and all payment options during evidentiary hearings, during which the feasibility of further negotiations is always an option." (D.83-09-054, p. 46.)

In D.83-09-054, The Commission specified that Payment Option No. 1 would be in effect for at most two years, and that Payment Option No. 2 and Payment Option No. 3 would be available for only one year, due to reservations about whether longer provision of these options would be in the public interest. Our intent at that time was that a final SO 4 would be approved by the set expiration dates. When this proved overly optimistic, we extended by D.84-08-035 all three payment options of interim SO 4 until further order.

D.84-08-035 also addressed a motion for a revised procedural schedule for the SO 4 proceeding which had been filed by the Independent Energy Producers Association (IEP) and supported by the Independent Power Corporation (IPC). These two parties requested that hearings on a revised incremental energy rate for use in Payment Option No. 3 of Interim SO 4 be commenced no later than October 1984. According to IEP, the incremental energy rate in interim SO 4 is not a viable option for gas-fired cogeneration projects. In D.84-08-035 we denied IEP and IPC's request; stating that:

> "A change in one term would require the reexamination of all other terms of the standard.
>
> "A change in one term would require the reexamination of all other terms of the standard offer. We prefer to maintain the status quo and adopt modifications to Standard Offer No. 4 following the evidentiary hearings now scheduled in this proceeding.

. . .

> "Upon completion of [Phase I of the hearings on a final SO 4], the Commission will make a determination either in its decision in Phase I or by ALJ Ruling whether to segregate the issue of incremental energy rate valuation and hear the matter prior to Phase II hearings." (D.84-08-35, p. 4.)

In April 1984, the Commission issued an Order Instituting Investigation (I.) 84-04-077 into the transmission system operations of the major electric utilities, in response to alleged transmission constraints on PG&E's transmission system which might restrict the development of QFs in the northern portion of PG&E's service territory.

On October 17, 1984, the Commission issued D.84-10-098, which suspended Payment Option No. 3 of SO 4 for PG&E for QF projects over 50 MW, in response to reports from our Public Staff and PG&E that a number of large oil and gas cogenerators had signed or were anticipated to sign this offer. While we had not imposed a MW limitation on the quantity of QFs which could sign Payment Option No. 3, we had earlier recognized potential problems:

> "We recognize the benefits of having oil and gas cogenerators on the system to displace the units, but only to the extent that: 1) cogeneration results in a more efficient use of fossil fuels (i.e., the cogenerator's actual incremental energy rate is lower than the utility's) and, 2) California's resource base, no matter how well it can be diversified, may require some oil and gas generation units to meet demand. We are concerned, however, that this energy payment option could, over time, provide incentives to oil and gas cogenerators that are not commensurate with the benefits described above." (D.83-09-054, pp. 44, 45.)

We ordered additional filings assessing how much of the capacity signed under SO 4 with PG&E is likely to actually come on line and how much additional capacity, particularly large cogeneration projects, could be expected to sign contracts within a year. We also set an en banc hearing for November 5, 1985 to receive comments from PG&E, the Public Staff, and other

interested parties regarding the suspension of Payment Option 3. We stated that:

> "We intend to make any adjustments to Payment Option #3 as soon as possible so that any uncertainties aroused by today's actions will be short-lived. Therefore, this suspension order will automatically expire on December 5, 1984 unless the Commission issues an order outlining specific steps for further action on this issue on or before that date." (D.84-10-098, p. 4.)

At the en banc hearings and through written comments as well, parties were asked to respond to a motion of the Public Staff to expand the suspension to include SO 2 and the remainder of SO 4, for projects over 50 MW. PG&E requested an even broader suspension, of all of interim SO 4 and all of SO 2 for projects over 10 MW.

On December 5, 1984, the Commission issued a decision extending the suspension to January 16, 1985, stating that:

> "[W]e conclude that the cornerstone for determining the extent of QF capacity in PG&E's service territory is the adoption of a milestone procedure to mark the progress and commitment of each QF project. It is clear that such steps have not yet been taken by PG&E. Further, without such a procedure it is difficult for this Commission or any other party to verify the exact extent of the impact of QF development on PG&E's resource plan and its ratepayers.
>
> "[W]e find that it is reasonable to continue the suspension of Payment Option #3 of PG&E's interim Standard Offer 4, but coordinate any further expansion or removal of that suspension with the milestone procedure to be considered in I.84-04-077. We believe that a sufficient basis to maintain the status quo has been presented by PG&E. We find, however, that no further action is warranted until we have had the opportunity to consider the comments and milestone proposals to be presented during the public hearing scheduled for December 17, 1984 in I. 84-04-077." (D. 84-12-027, pp. 2, 3.)

In response to the Commission directive, a committee of representatives from the Public Staff, the utilities, and QFs prepared a milestone procedure designed as an interconnection priority procedure (IPP), and presented it at the December 17 public hearing. On January 16, 1985, we adopted a slightly modified version of the proposed IPP in D.85-01-038.

One of the modifications we required in the IPP was a new requirement that PG&E, SCE, and SDG&E compile basic project definition information on all QFs in their territories, through mailing a questionnaire if needed, and that they file summaries of the results by March 18, 1985. They have made the compliance filings, and also supplemental filings providing more detail as requested by the assigned Commissioner.

Also on January 16, we again extended the suspension of Payment Option No. 3 of SO 4 for PG&E for QF projects over 50 MW. The Public Staff had recommended in a motion filed on January 4, 1986 that the suspension be extended until "either (a) 18 months plus a 20-day notice period from the date the Interconnection Priority Procedure is adopted, or (b) the issuance of a final decision on long-run avoided cost pricing [in this proceeding]." (Pulbic Staff Motion, p. 10) In D.85-01-040, we concluded that:

> "We do not think that QF development is served by placing the larger QFs 'on hold' for 18 months. Rather, we believe that is our responsibility to maintain a continuing review of QF development in PG&E's service territory, especially in light of the absence of any examination of estimates in an evidentiary proceeding open to all interested parties." (D.85-01-040, p. 3)

Instead, we continued the suspension only until April 17, 1985, to give us time to review the utility filings in compliance with the adopted IPP.

On January 31, 1985, SCE filed a motion (SCE Motion) seeking an emergency ex parte order providing a suspension of Payment Option No. 3 of SO 4 in its territory comparable to that in place for PG&E. Public Staff filed a response in support of SCE's motion and renewing its arguments in support of its

October 29, 1984 recommendation to suspend all payment options under interim SO 4 until adoption of a final SO 4. We concluded, in D.85-02-069, that SCE is at some risk of having QF energy supplies exceed its needs, and that it was reasonable to grant the requested suspension until April 17, 1985. We stated that, upon receipt of the IPP filings, we would review the available information to determine the accuracy and verifiability of the current estimates of QF development in both PG&E's and SCE's service areas.

III. Discussion

The lengthy compilation of occurrences and Commission decisions reiterated above shows the rather tortuous path leading to today's decision. As discussed below, we still do not have sufficient information to feel absolutely confident that we have a good grasp of likely QF development in California. However, much more information is available now than at the time of our initial actions last fall.

Questions which must be examined include:

1. How much of the signed QF capacity in each utility's service area is likely to come on-line and what is its likely impact on system reliability?

2. Should the partial suspension of interim SO 4 lapse?

3. What would be the effects if interim SO 4 were suspended until a final SO 4 is available?

4. Would a second negotiating conference be successful?

5. Are the capacity payments in SO 4 reasonable?

6. Are the energy prices in Payment Option No. 1 and Payment Option No. 2 of SO 4 reasonable?

7. Are the incremental energy rates in Payment Option No. 3 of SO 4 reasonable?

We will address each of these issues in turn.

Viability and Effect of QF Projects with Signed Contracts

SCE asserts that it already has under contract 95 percent of the QF capacity which it will need through 1994 (SCE Motion, p. 2). PG&E claims that the capacity prices being offered in SO 4 are substantially too high, mainly because of the unexpectedly large number of QF contracts it has signed since the prices were established.

Determination of the accuracy of PG&E's and SCE's assertions is critical to our decision regarding whether to extend or expand the existing suspension of a portion of interim SO 4. In this section we examine the information available to us to assess whether it supports PG&E's and SCE's positions. We also look at comparable information for SDG&E, to determine whether action regarding its interim SO 4 might also be warranted.

Table 1, Table 2, and Table 3 show, for PG&E, SCE, and SDG&E respectively, the amounts of capacity which were operational, under contract, and under active discussion at the end of 1984 according to the Quarterly Status Reports which the utilities file regularly with the Commission.[1]

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[1] Quarterly Status Reports are required filings by prior order of this Commission. For the purposes of this order, we take notice of the Quarterly Status Reports filed for December 31, 1984.

TABLE I

Qualifying Facility Projects
Pacific Gas and Electric Company
December 31, 1984
(Megawatts)

Project Type	Under Contract, Operational	Under Contract, Non-Operational	Under Active Discussion
Cogeneration:(1)			
Smaller than 25 MW	124	207	118–199
25–49.9 MW	148	656	473
50 MW or larger	75	890	2804
Solid Waste/Biomass:			
Cogeneration	87	411	24
Non Cogeneration	43	716	376
Geothermal	80	93	2
Solar	6	31	1
Wind	271	2024	287
Hydro	107	624	272
Other	1	0	0
TOTAL	942	5651	4462–4542
TOTAL EFFECTIVE CAPACITY	641	3534	3800–3877

(1) Fueled by other than solid waste/biomass.

TABLE 2

Qualifying Facility Projects
Southern California Edison Company
December 31, 1984
(Megawatts)

Project Type	Under Contract, Operational	Under Contract, Non-Operational	Under Active Discussion
Cogeneration:(1)			
Smaller than 25 MW	159	3	105
25–49.9 MW	75	172	175
50 MW or larger	55	1486	420
Solid Waste/Biomass	35	459	272
Geothermal	15	411	85
Solar	15	107	36
Wind	222	788	1327
Hydro	72	36	53
TOTAL	648	3463	2474
TOTAL EFFECTIVE CAPACITY	413	2418	1214

(1) Fueled by other than solid waste/biomass.

TABLE 3

Qualifying Facility Projects
San Diego Gas and Electric Company
December 31, 1984
(Megawatts)

Project Type	Under Contract, Operational	Under Contract, Non-Operational	Under Active Discussion
Cogeneration:(1)			
Smaller than 25 MW	66	0	54
25–49.9 MW	0	0	29
50 MW or larger	0	0	0
Solid Waste/Biomass	0	47	75
Geothermal	0	0	0
Solar	5	2	17
Wind	3	0	4
Hydro	2	0	8
TOTAL	76	49	188
TOTAL EFFECTIVE CAPACITY	62	42	154

(1) Fueled by other than solid waste/biomass.

PG&E has almost 2,200 MW more QF capacity under contract but not yet operational than does SCE (5,651 MW compared to 3,463 MW). However, over 80 percent of this difference is attributable to the larger amounts of wind and hydro capacity which PG&E has under contract. Because of the expected lower capacity factors during peak periods of as-available capacity, the nameplate capacities of such projects must be discounted significantly for system planning purposes. PG&E has only about 1,100 MW more "effective" capacity (as defined in Appendix A) under contract than does SCE. Because of the importance of considering effective capacity rather than nameplate capacity, we present much of the analysis in this section in terms of effective capacity.

As made clear by Table 3, QF activity is much less pronounced in SDG&E's area than for the other two utilities. SDG&E has projects totalling only about 42 MW of effective capacity under contract but not yet operational, and only about 150 MW of effective capacity under discussion.

As mentioned above, the utilities have also filed information regarding the status of non-operational QF projects which responded to the questionnaires mailed at our direction. Responses to some of the more pertinent questions by QFs which have signed contracts are summarized in Table 4. For PG&E, information is also presented for those projects not on transmission waiting lists in the northern portion of PG&E's territory or in the Altamont Pass area. This is important because many of the projects on the two waiting lists may proceed only if other projects with transmission priority do not go forward or PG&E builds the necessary transmission upgrades.

TABLE 4

Comparison of Responses
To Project Questionnaire
Of Projects with Signed Contracts
(Percent of Effective Capacity Responding)

	PG&E		SCE	SDG&E
	All	Not on Waiting Lists		
1. Critical Path Permits Applied for ..	47%	47%	66%	100%
2. Critical Path Permits Received	30%	36%	35%	4%
3. All or Portion of Financing Secured	43%	39%	40%	100%
4. Generating Equipment Ordered	17%	14%	26%	0%
5. Project Construction Begun	16%	20%	19%	0%
No. of Responses	206	125	61	5
Effective MW of Responses.....	2,091	1,436	1,895	8
No. of Signed Contracts (12-31-84)	308		115	10
Effective MW of Signed Contracts (12-31-84)	3,534		2,418	42

As can be seen, there was significant variation in the response rates to the questionnaires. SCE had a much larger response rate in terms of effective capacity under contract (78 percent) than did either PG&E (59 percent) or SDG&E (19 percent). This disappointing response reduces the credibility of the results. It is not clear whether those QFs which responded are representative of the other QFs.

We have hoped that the survey results would shed some light on the commonly held belief that projects signed by SCE are more likely to come on line than those signed by PG&E. If the responses can be viewed as reasonably representative of all QFs, then Table 4 supports this thesis, but only weakly. While a larger percentage of projects in SCE's area have applied for their critical path permits, about the same percentage of projects which responded to the questionnaires have received their permits in the two areas. Similary, while a larger percentage of projects in SCE's area say that they have ordered their generating equipment, about the same percentage in both areas are under construction.

Another measure of whether PG&E's signed capacity should be viewed as seriously as SCE's is the number of earlier contracts which have been cancelled. PG&E's December 31, 1984 Quarterly Status Report reveals that 21 signed projects with a total effective capacity of about 100 MW have "terminated." At the assigned Commissioner's request, SCE has informed us (see letter attached as Appendix B) that 5 signed projects have cancelled their contracts with SCE. Their total effective capacity is about 137 MW. PG&E's failed projects include 13 very small wind, hydro, or photovoltaic QFs totalling about 50 kilowatts in effective capacity, whereas the cancellation reported by SCE include only two projects under 1 MW. Excluding the very small projects, we conclude that the record of cancelled contracts indicates, if anything, that PG&E has been the more successful of the two utilities.

At the request of the assigned Commissioner, our staff has provided calculations of the effect of the existing signed QF capacity on the reserve margins and on the value of additional QF capacity for PG&E and SCE.[2] Those calculations, which are presented in detail in Appendix A, indicate that PG&E is likely to have much larger reserve margins through the late 1980s and early 1990s than SCE.

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[2] While these calculations were performed by members of the Public Staff Division (PSD), the results and the use we make of them do not in any way represent the position of the PSD. The provision of these calculations at the request of the assigned Commissioner does not prejudice PSD's position as an independent party in these proceedings.

In this analysis, PG&E's and SCE's nameplate signed capacity is translated into effective available peak capacity. Three scenarios are then created, representing development of 80 percent, 50 percent, and 30 percent, respectively, of the effective QF capacity under contract but not yet operational.

We realize that the probability that only 30 percent of QFs under contract will materialize is fairly low. We prefer to view the three scenarios as three versions of potential need for additional QF capacity. Thus, the 30 percent scenario would present a greater need for additional QF capacity, which could occur if, in addition to QF development being low, demand growth is higher than projected or utility plants such as Diablo, Helms, or San Onofre operate at low capacity factors.[3] The 80 percent scenario reflects lower need for additional QF capacity, which could occur if most of the signed projects come on-line, if demand growth is low, and/or if utility plants operate better than expected.

PG&E's and SCE's reserve margins through 1995 under the 80 percent and 30 percent scenarios are shown in Figure 1. The difference is striking. Under even the scenario of development of 30 percent of signed contracts (or the equivalent effect on reserve margins due to factors such as higher load growth), PG&E's reserve margin remains above 27 percent through 1992, though it falls to 18 percent by 1995. If the 80 percent scenario occurs, PG&E's reserve margin could peak at 49 percent in 1989 and still be 27 percent in 1995. By contrast, even if 80 percent of SCE's signed QF contracts produce operating projects, its reserve margin would reach a high of only 26 percent in 1988, dropping to 13 percent by 1995. Under the more pessimistic scenario of 30 percent QF development, SCE's reserve margin would remain at about 20 percent through 1988, but then falling rapidly to critical levels, reaching less than 17 percent by 1995.

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[3] For example, the need for additional QF capacity under the 30 percent scenario for PG&E corresponds roughly to development of 80 percent of signed QF capacity coupled with annual load growth through 1992 of 3.2 percent (rather than the 1.4 percent assumed in the calculations shown in Appendix A).

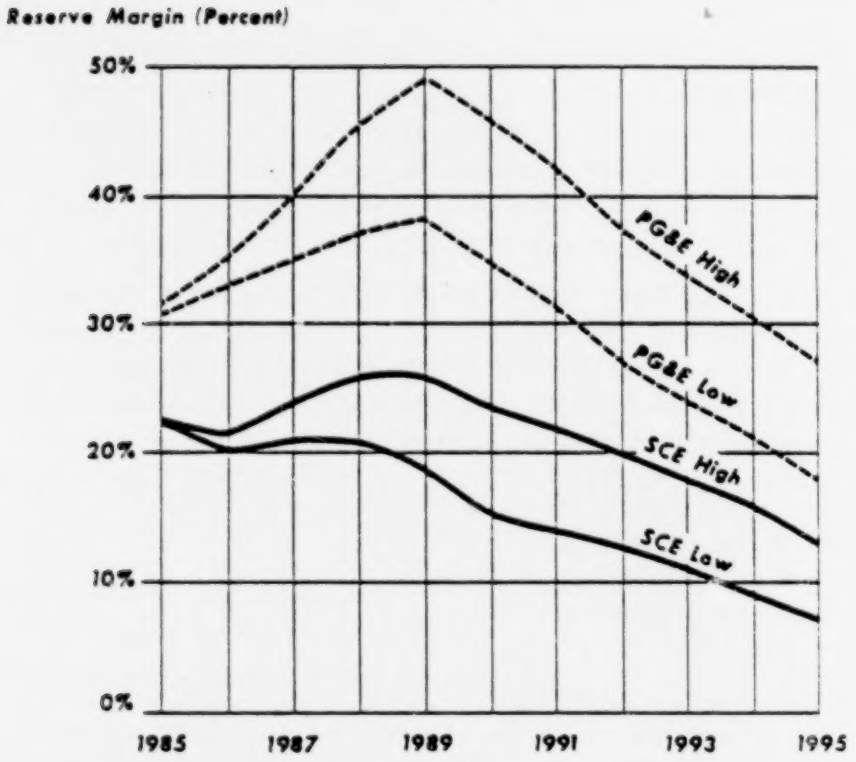


Figure 1 PG&E and SCE Reserve Margins with High and Low Levels of QF Development

We recognize that this analysis is somewhat simplistic. However, it does provide useful insight into the situation at hand. It appears fairly unlikely that PG&E will fall seriously short of capacity through the next decade even though additional QF capacity could enhance system reliability somewhat. Given the uncertainty surrounding QF development and other factors such as load growth, we conclude that SCE is premature in asserting that it needs only 158 MW of additional QF capacity through 1994 (SCE Motion, Table 1).

Should the Partial Suspension of Interim Standard Offer 4 Lapse?

In establishing interim SO 4, we expected that it would be in effect for only a short while. Because of concerns we had about both the levelized energy price option (Payment Option No. 2)

and the incremental energy rate option (Payment Option No. 3), we initially made them effective for only one year. At the time we extended these options in August 1984, we still did not foresee any serious problems with the overall payment levels, and expected that the terms of interim SO 4 would remain in effect until a final SO 4 became available.

Since last August, rapid changes in the QF market have outstripped the pace of our regulatory process. We have already imposed partial suspensions of interim SO 4 for PG&E and, later, for SCE. Now we must decide whether the suspension should be allowed to lapse, or whether other action is needed.

While SCE and, to a lesser extent, PG&E still have some need for additional capacity, the reserve margins for each utility under even the worst case scenario examined are high enough to indicate that the capacity payments in interim SO 4 (which are those which were offered in SO 1 and SO 2 at the time of the negotiating conference) may now overvalue new QF capacity.

Comparable calculations were not made for SDG&E, because it has not asserted that too many QF projects are signing contracts to sell power to SDG&E. We are concerned, however, about whether its prices being offered under interim SO 4 are too high. Even if only a limited number of QF projects are developed in SDG&E's region, if the payments are too high then ratepayer indifference is no longer maintained.

In Application (A.)82-12-57, SDG&E's 1984 general rate case, SDG&E proposed reductions in the capacity payments available to QFs in its SO 1 and SO 2, based on its forecast of the probability of need for additional capacity. We adopted these adjustments in D.83-12-065 as reasonable. Since the capacity payments which had been in effect for SO 1 and SO 2 prior to D.83-12-065 were equal to the capacity payments which are still in interim SO 4, we conclude, based on D.83-12-065, that they are too high for interim SO 4 as well.

The capacity payments must not be looked at in isolation, however. In deciding whether the terms of a proffered contract are acceptable, a third party undoubtedly looks at energy and capacity payments as a package. We recognized in D.84-08-035,

in considering whether the incremental energy rates in Payment Option No. 3 should be modified, that a change in one term of an interim SO 4 contract would require the reexamination of other components as well. Thus, in an assessment of what changes, if any, are appropriate for the capacity payments in interim SO 4, the energy payment component must be considered as well.

It is obvious that significant changes have occurred in the energy markets since the negotiating conference was held in June 1983. Natural gas prices have stabilized and even fallen, and further reductions are quite possible. In Table 5, the incremental costs of natural gas to PG&E, Southern California Gas Company (SoCal), and SDG&E are shown. PG&E and SDG&E have experienced substantial price reductions in the last 20 months, and if the effects of inflation were removed, Table 5 would show that SoCal's incremental cost of gas has also decreased, in real terms. There are at least two other easily available comparisons which provide a measure of changes in the utilities' avoided energy prices: The rates which utilities pay for natural gas for use in their own generating units (Table 6) and the avoided costs prices paid to QFs operating with short-run standard offer contracts. (Table 7). Natural gas rates for electric generation have declined for all three utilities, from 2 percent to 17 percent. SCE's and SDG&E's short-run avoided cost energy payments have declined substantially, by 11 percent and 15 percent respectively. PG&E's energy payments have increased dramatically, due to higher incremental energy rates adopted in its December 1983 general rate case decision. However, as pointed out in Table 7 (see also Table 14), that rate case decision also authorized PG&E to reduce its short-run avoided cost energy payments about 20 percent after Diablo 1 and Diablo 2 become commercially operable. At current gas prices, these payments would be reduced to about 5.4 cents per kilowatt-hour, which is about 7 percent less than the June 1983 level.

TABLE 5

Incremental Costs of Gas
(Cents per therm)

	June 1983	April 1985	Change
PG&E	32.7	29.1	−11%
SoCal Gas	32.7	32.8	+0.3%
SDG&E	41.5	35.5	−14%

TABLE 6

Natural Gas Rates
For Electricity Generation
(Cents per therm)

	June 1983	April 1985	Change
PG&E	53.50	52.45	− 2%
SCE	46.33	45.44(1)	− 2%
SDG&E	55.00	46.99	−17%

(1) Weighted average of episode and non-episode day rates.

TABLE 7

Non-Time Differentiated
Avoided Cost Energy Payments
(cents per kilowatt-hour)

	June 1983	April 1985	Change
PG&E	5.8	7.2(1)	+24% (−7%)(1)
SCE	4.6	4.1	−11%
SDG&E	6.2	5.3	−15%

(1) PG&E's energy payment will be reduced by about 13 percent after Diablo 1 becomes commercially operable and an additional 8 percent after Diablo 2 becomes commercially operable. At current G-55 rates the energy payment would average 5.4 cents per kilowatt-hour after Diablo 1 and Diablo 2 become commercially operable.

While we do not know what energy price forecasts were relied upon by the parties to the negotiating conference, we suspect that they did not predict the current turn of events. Thus, the energy components of interim SO 4 may be overstated. The rapid rate at which PG&E and SCE have signed interim SO 4 contracts indicates that the overall pricing terms, including both capacity and energy provisions, may be seen as very favorable by QFs.

If significant amounts of additional QF projects are allowed to sign contracts with the prices currently offered, ratepayers may indeed, as PG&E, and SCE assert, be required to pay more for the capacity and electricity than is reasonable. Because of this possibility, we agree with PG&E, SCE, and our staff that some action must be taken to protect ratepayers. The partial suspension cannot merely be allowed to lapse.

Possible Effects of a Suspension of Interim Standard Offer 4

From our viewpoint, continuation and expansion of the current limited suspension of interim SO 4 might be the easiest regulatory response to the current situation. It would require a minimum of staff resources and minimal delay in the Phase II hearings on the long-run avoided cost methodology. Since the utilities appear to be in no imminent danger of capacity shortfalls, a complete suspension might protect ratepayers while the final long-run standard offer is being developed.

Public Staff has repeatedly supported action along these lines. On October 29, 1984, PSD requested that PG&E's suspension be expanded to include SO 2 and the remainder of SO 4, for projects over 50 MW. On January 4, 1985 PSD recommended that the suspension be extended about 19 months, to allow time to ascertain how much of the QF capacity now under contract will materialize. or until the issuance of a final decision on long-run avoided cost pricing. Most recently, in its response to SCE's motion requesting suspension of Payment Option No. 3 for projects over 50 MW in its territory, PSD recommended suspension of all payment options of interim SO 4 until a final SO 4 is adopted, unless prices are adjusted to reflected current conditions through another interim Commission order.

In informal discussions, a number of other parties have also seemed agreeable to this approach. Other parties, most notably QFs negotiating contracts with the utilities, do not support continuation or expansion of the suspension.

We see several potential problems with a significant expansion of the current suspension. First, despite any amount of reassurances which we could make to the contrary, it might be viewed by QFs and the financial community as a reduction in our commitment to the development of the QF industry. That view certainly would not be accurate.

Second, some QF projects which are under consideration and which may be in ratepayers' best interests in terms of meeting future energy needs may not be able to survive a lengthy suspension of the availability of standard offer contracts. We realize that many QFs could wait until a final SO 4 is approved, and others might successfully enter into negotiations of non-standard contracts with the utilities to allow their projects to proceed this year.

This brings us to another concern. One of the benefits of the standard offers is that they provide reasonable back-up alternatives to QFs who want, for whatever reason, to negotiate non-standard contracts. They provide a measure of the reasonableness of the utility's negotiations and an alternative if negotiations do not yield terms acceptable to both the QF and the utility. Suspending the standard offers would remove this safeguard.

Further, the very action of suspending the standard offers for a significant period of time could be viewed by the utilities as a signal that the Commission might look unfavorable upon non-standard contracts signed in the interim unless the contract terms are significantly below the present standard offers. This response would not be surprising, since we would essentially be concluding that the existing yardstick is no longer reasonable.

While expansion of the suspension has been presented as an easy solution which would not require staff time or delay development of the final long-run standard offer, it may not be so simple. We have already had to address requests from QFs to allow switching to the interim SO 4 offer. It is easy for us to imagine that other QFs would similarly ask for special consideration if the

offer were completely suspended. We would confront the Hobson's choice to either devote the staff resources needed to evaluate such requests, or allow absolutely no exceptions to the suspension.

It has been suggested that there may not be significant amounts of QF capacity which would want to sign contracts in the next year or so, in effect that the "gold rush" effect that appears to have occurred in recent months may have already resulted in the signing of contracts for almost all QF projects which were being considered by potential developers. The utilities' Quarterly Status Reports appear to refute this possibility. As summarized earlier in Table 1 and Table 2, PG&E is in active discussion with potential QF projects totalling over 4,500 MW; developers of projects totalling over 2,400 MW are discussing contracts with SCE.

Rather than expand the suspension, we could simply extend it for a lengthy time period, as suggested by PSD in its second motion filed January 4, 1985. We would have to look carefully at the prices available to QFs under the remaining portions of SO 4. Utility filings show that significant amounts of capacity are signing up under these options. Thus, ratepayers could still bear a significant financial burden due to projects which would sign under these other offers if they were left intact.

Would a Second Negotiating Conference Serve A Useful Purpose?

A second negotiating conference has been suggested by a number of parties as a potential approach to adjust the terms of interim SO 4 which would, as would a complete suspension of interim SO 4, involve only a limited amount of the parties' time and thus cause only a minimal slippage in the development of the final long-run standard offers.

The first negotiating conference took five weeks, plus advance preparation time by the parties and time summarizing the results for submission to the Commission. While it was clearly successful, we would not be prepared to embark upon another negotiating effort of this magnitude.

The scope of a second negotiating conference would have to be very carefully and narrowly defined, to allow quick resolution.

However, capacity prices, which were not addressed in the first negotiations, are a central issue now. Questions regarding how much of already-signed QF capacity will actually materialize, what utility load growth will be, what utility resources should be included in determining need for additional capacity, and how additional capacity should be valued are too broad and much too controversial to give us any confidence that quick resolution is at all possible through the negotiating approach.

Because of our desire to not delay further the development of the final long-run standard offers, we conclude that a second negotiating conference should not be held.

Adopted Changes to Interim Standard Offer 4

Since the present interim SO 4 is a negotiated offer, there was no evidentiary record and we were thus not able to make findings regarding its reasonableness when it was adopted in D.83-09-054. We accepted it because it was a negotiated offer agreeable to all parties.

The conventional avenues which would allow us to protect ratepayers in light of changed circumstances—continuation or expansion of the present partial suspension, establishment of a second negotiating session, or commencement of focused evidentiary hearings—all have problems which we have discussed. Of these, if we must choose among them, we prefer a complete suspension of all of interim SO 4 until a final long-run standard offer is available. We do not believe that it is in anyone's interest to create another procedure to solve a short-term problem which would delay Phase II of these proceedings

This places us in a quandry. We have searched for a solution less draconian than a complete suspension, so that the benefits of having standard offers in-place can be preserved while the Phase II hearings proceed. The only alternative which appears feasible is for us, using our best judgment, to present potential modifications of some of the terms of interim SO 4, to levels which would better protect ratepayers. We propose this unusual approach because it may be preferable to the complete suspension which otherwise appears necessary.

As detailed in the following sections, we present certain modifications to the prices in interim SO 4 for comment by the parties. While we try in this decision to fully explain their basis, a workshop will be held on May 3, 1985 to allow parties to request any further clarification which may be needed. Parties are expected to file comments by May 10, 1985 regarding whether they prefer adoption of these modifications or a complete suspension of interim SO 4 until a final long-run standard offer is available.

To prevent a "gold rush" of projects asking to sign the current interim SO 4, we suspend all payment options of interim SO 4, effective today. Based on the filed comments, we plan to decide whether to leave the suspension in place or to implement the price changes we have proposed by June 5, 1985.

We conclude that QFs which sign one of the revised interim SO 4 offers (if after filed comments we adopt the revisions) should have the option of switching to a final SO 4 contract when it becomes available. We believe that the two proposed modifications—a reduction in prices and the allowance of future contract switching—combine to provide both protection to ratepayers and assurance to QFs regarding the reasonableness of the modified interim SO 4.

As a further protection to ratepayers, we would allow the revised contract terms to be in effect for each utility only until a set amount of new QF capacity enters into contracts (standard or non-standard) with the utility. That amount is 1,250 MW for each of PG&E and SCE and 200 MW for SDG&E, counted from April 17, 1985. At that point, all of interim SO 4 would be suspended for the utility until a final long-run standard offer becomes available.

If a modified interim SO 4 is reinstated on June 5, 1985, it should contain a requirement that the QF meet all milestones in the adopted Interconnection Priority Procedure in order for the contract to remain in force. While the 1,250 MW limit (200 MW for SDG&E) would apply to all signed contracts, not just interim SO 4, we conclude that this requirement in interim SO 4 is needed to reduce any tendency there may be for would-be

developers without serious projects to sign contracts and possibly prevent other more viable projects from proceeding.

From the time that we approved the terms of interim SO 4 in D.83-09-054, we have expressed reservations about resource planning issues relating to oil and gas cogeneration. They will be addressed in Phase II of the evidentiary portion of these proceedings. These issues are critically important in light of the quantity of large cogeneration projects which are discussing contracts with the utilities at this time.

According to the utilities' Quarterly Status Reports (summarized in Table 1 and Table 2), PG&E and SCE are discussing contracts for large (over 50 MW) cogeneration projects whose capacities total over 3,200 MW. These projects alone would more than fill the 2,500 MW of additional QF capacity we would allow for these two utilities before suspension of the modified interim SO 4.

Because of questions we still have regarding the implications of large cogeneration projects on a utility's avoided costs, we conclude that such projects should not be allowed to sign interim SO 4 contracts until we can examine these issues in Phase II. Thus, we will continue the suspension of Payment Option No. 3 of interim SO 4 for projects over 50 MW until a final long-run standard offer is available. We also extend this suspension to SDG&E.

We continue to expect utilities to negotiate in good faith with large cogenerators based on current estimates of long-run avoided costs, but remind them that the reasonableness of such negotiated contracts will be reviewed carefully by this Commission.

Capacity Payments in Interim Standard Offer 4

As discussed earlier, the PSD, at the assigned Commissioner's request, provided calculations of the possible effects of existing signed QF capacity on the value of additional QF capacity for PG&E and SCE. The method and results are contained in Appendix A.

As described in Appendix A, additional capacity is valued based on utility reserve margins under each of three scenarios.

Additional capacity was assumed to have the full value of a gas turbine in any year in which the reserve margin without it would fall below 20 percent, and to have no value if the reserve margin without it would be greater than 35 percent. The assumed capacity value varies linearly between the value of a gas turbine and zero for reserve margins between 20 percent and 35 percent. For each scenario, staff provided a table of levelized prices for a 1,000 MW block of additional firm capacity.

In Table 8, we present some of the results for PG&E and SCE for the scenario of 80 percent QF development. For this scenario, application of the above formula indicates that the capacity value of a QF signing a 20-year contract for firm operation beginning in 1986 should be 35 percent of that in PG&E's current interim SO 4 if it signs with PG&E but 78 percent of that in SCE's interim SO 4 if it signs with SCE. This striking difference between the capacity value of additional capacity to the two utilities carries over to the other scenarios analyzed as well. Comparable results for the 30 percent QF development scenario still show capacity values to be only 50 percent of PG&E's current interim SO 4 capacity payment, but 93 percent of SCE's, for a QF committing to 20 years of firm operation beginning in 1986.

TABLE 8

Calculations of Capacity Payments For Additional 1000 MW Block QFs

Levelized $/kW-year (Percent of SO 4 Capacity Payment)

PG&E: Assuming 80% of Signed QFs Materialize

Year Operation Begins	Number of Years of Firm Delivery 1	10	20
1985	19(23)	4(4)	40(31)
1986	1(1)	4(4)	47(35)
1987	0(0)	10(8)	57(39)

SCE: Assuming 80% of Signed QFs Materialize

Year Operation Begins	Number of Years of Firm Delivery 1	10	20
1985	73(90)	79(73)	105(80)
1986	83(95)	84(72)	112(78)
1987	68(72)	89(70)	119(77)

Because of the large amounts of QF projects which have signed contracts with PG&E and SCE since interim SO 4 was negotiated, and because our analysis of the effects of such capacity indicates that the value of additional QF capacity to the utilities and ratepayers is significantly less than the capacity payments now in interim SO 4, we conclude that the capacity payments in PG&E and SCE's interim SO 4 should be adjusted if it continues to be available for new projects. Since large amounts of QF projects are still under discussion, we conclude further that updated capacity payments should be based on allowing 1,000 MW of additional capacity to enter into contracts (standard or non-standard) with the utility.

Because of the expectation, however, that not all projects which sign contracts will actually reach fruition, we would allow the revised capacity prices to remain in effect for each utility until new QF projects totalling 1,250 MW have come under contract with that utility, measured from April 17, 1985. If 80 percent of these projects materialize, this would result in 1,000 MW of on-line capacity. If that limit is reached for either PG&E or SCE, then all of interim SO 4 will be suspended for that utility until a final SO 4 becomes available.

The capacity tables calculated by staff consider the effect of only those QF projects which have signed contracts by December 31, 1984. Use of those results for pricing a 1,250 MW block of QF projects entering into contracts after April 17, 1985 would overvalue that capacity, since projects signed between January 1 and April 17, 1985 would not be considered.

We instruct PG&E and SCE to file in these proceedings by May 1, 1985 a statement listing all QF projects by size, technology, and contract type, which have entered into contracts between January 1, 1985 and April 17, 1985, or which have cancelled contracts during that period. If we choose to adopt modifications to capacity prices on June 5, 1985 we will ask staff to update the capacity tables commensurately.

As explained earlier, calculations were made for three scenarios of development of QF projects already under contract. If modifications are adopted on June 5, they will be the numeric average of

the calculated capacity values resulting from the three scenarios, updated to incorporate the results of PG&E's and SCE's May 1 filings. The complete tables of such capacity values based on contracts through December 31, 1984 are shown in Table 9 and Table 10, for illustration.

This capacity adjustment method is not an ideal solution to the difficult problem of establishing accurate capacity prices. We have wrestled with other adjustment mechanisms such as PG&E's Energy Reliability Index and staff's Reliability Adjustment Factor proposed recently in SCE's 1985 general rate case (A.83-12-53). Not being completely satisfied with either of these two mechanisms, we ordered both PG&E and SCE in conjunction with staff, to develop improved capacity adjustment mechanisms in subsequent proceedings based on an Expected Unserved Energy (EUE) reliability criteria. Future analyses of the EUE criteria and other measures of reliability should provide us with the opportunity to institute a more refined capacity adjustment mechanism. Lacking such analyses at this time, we would adopt capacity price adjustments for interim SO 4 based on a reserve margin reliability criterion as described above.

As discussed earlier, we found in D.83-12-065 that the same capacity prices now in SDG&E's interim SO 4 were too high for SO 1 and SO 2, and adopted modified capacity payments for SDG&E's SO 1 and SO 2. We propose that the modified capacity payments now in effect for SO 1 and SO 2 be incorporated into a revised interim SO 4 for SDG&E as well.

For SDG&E, we would require suspension of the modified interim SO 4 if new QF projects totalling 200 MW sign contracts with SDG&E before a final SO 4 becomes available. This is comparable, relative to their peak loads, to the 1,250 MW limit set for PG&E and SCE.

Energy Payments in Payment Option No. 1 and Payment Option No. 2 of Interim Standard Offer 4

We must also look at whether the energy payments in Payment Option No. 1 and Payment Option No. 2 of interim SO 4 should be adjusted. If they are too high, then adjusting only the capacity payments may not provide sufficient protection for ratepayers.

The annual average energy payments in Payment Option No. 1 and Payment Option No. 2 are shown in Table 11 and Table 12, respectively, for PG&E, SCE, and SDG&E. While we do not have access to the marginal fuel prices which formed the basis for negotiations in June 1983, other measures discussed earlier provide some basis for comparison.

The general trend since that time in incremental natural gas prices, prices for gas burned in utility plants, and short-run avoided energy payments is consistently downward, as chronicled earlier in Table 7, Table 8, and Table 9. A comparison of the energy prices for 1985 in the short-run SO 2 and the current SO 4 is also telling:

	SO 2 (¢/kWh)	SO 4 (¢/kWh)	SO 4/SO 2
PG&E:			
Now	7.2	5.55	0.77
After Diablo	5.4	5.55	1.03
SCE	4.1	5.70	1.39
SDG&E	5.3	6.40	1.21

TABLE 9

Pacific Gas and Electric
Firm Capacity Price Schedule
(Levelized $/kW-Year)
For the First 1000 MW of Additional QF Power

Average of Values from Scenarios 1, 2 and 3

Year Operation Begins	# Of years of Firm Delivery						
	1	5	10	15	20	25	30
1985	20	6	10	34	50	60	68
1986	6	1	13	41	57	68	76
1987	0	0	23	51	68	80	89
1988	0	0	36	65	83	95	104
1989	0	5	52	81	99	112	121
1990	0	17	70	99	118	132	141
1991	0	37	93	122	141	155	165

TABLE 10

Southern California Edison
Firm Capacity Price Schedule
(Levelized $/kW-Year)
For the First 1000 MW of Additional QF Power

Average of Values from Scenarios 1, 2 and 3

Year Operation Begins	# Of years of Firm Delivery						
	1	5	10	15	20	25	30
1985	74	77	92	105	115	123	129
1986	85	81	99	113	124	132	138
1987	80	84	105	120	132	141	148
1988	69	92	114	130	142	152	159
1989	77	105	128	144	157	167	174
1990	97	121	142	159	172	183	191
1991	111	135	155	173	187	198	207

TABLE 11

Payment Option No. 1

Forecasted Energy Price Schedule (Annual Average)
(¢/kWh)

Year	PG&E	SCE	SDG&E
1983	5.18	5.30	—
1984	5.47	5.60	5.90
1985	5.55	5.70	6.40
1986	5.79	6.00	6.40
1987	6.16	6.40	6.30
1988	6.70	6.90	6.70
1989	7.34	7.60	7.90
1990	7.84	8.10	8.60
1991	8.34	8.60	9.20
1992	9.01	9.30	10.00
1993	9.75	10.10	10.30
1994	10.54	10.90	11.10
1995	11.39	11.80	11.80
1996	12.24	12.60	12.60
1997	13.14	13.60	13.40
1998	—	—	14.20

1. Price calculated at primary generation level, with O&M expenses included, based on gas as the incremental fuel.

2. Price calculated includes line losses, O&M expenses, and is oil/gas based.

3. Price calculated at primary generation level, with O&M expenses included, and is oil/gas based.

TABLE 12

Payment Option No. 2

Levelized QF Energy Prices (Annual Average)
(¢/kWh)

Initial Year of Delivery	5-Year Levelization Forecast			10-Year Levelization Forecast		
	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
1983	5.57	5.7	—	6.27	6.5	—
1984	5.85	—	6.3	6.66	—	7.2
1986	6.62	—	7.0	7.61	—	8.1
1988	7.69	—	8.3	8.85	—	9.4

For SCE and SDG&E, interim SO 4 energy prices far outstrip those available under SO 2. Only PG&E offers higher short-run avoided-cost energy payments. After Diablo Canyon becomes commercially operable, its SO 2 prices are also expected to fall below the energy payment offered in interim SO 4.

Since, according to the incremental energy rate forecasts contained in Payment Option No. 3, the marginal efficiency of fuel usage is expected to increase somewhat during the next five years, we estimate that the streams of energy payments in Table 11 imply an underlying annual increase in oil or gas prices of about 7.3 percent (PG&E and SDG&E) to 7.5 percent (SCE).

We realize that the present oil and gas glut and the lull in inflation may not last throughout the forecast period, and a 7.5 percent escalation rate for natural gas may not be unreasonable in the future. But we certainly have not seen such price increases during the past 20 months, and the 1985 energy prices in interim SO 4 are clearly too high for SCE and SDG&E.

A final factor also indicates that the energy prices may be high for another reason. As Table 14 in the next section illustrates, the amount of resources on line can have a dramatic effect on marginal system efficiencies. Thus, we would expect that successful operation of an appreciable amount of the QF projects which have signed contracts since interim SO 4 was negotiated would have the effect of driving incremental energy rates lower than had been expected in June 1983. This would proportionally reduce the energy costs avoided by the utilities as a result of the next block of

QF projects signing up. If this were not reflected in the energy prices, then ratepayers would not receive this benefit of QF development.

We will not attempt to forecast energy prices at this time. However, all indications are that the payments in Payment Option No. 1 and Payment Option No. 2 are too high except perhaps the 1985 payments for PG&E. As an alternative to suspension of these payment options until proper energy forecasts can be examined through evidentiary hearings in Phase II, we propose an across-the-board reduction in these payments of 10 percent, except for the 1985 energy payments for PG&E. We ask for parties' comments by May 10, 1985, as discussed previously.

Incremental Energy Rates in Payment Option 3 of Interim Standard Offer 4

The incremental energy rates (IERs) which form the basis of Payment Option No. 3 must also be examined, and are set forth in Table 13. As noted above, IEP and IPC have asserted that the IERs in PG&E's Payment Option No. 3 are too low and need revision. According to IEP, PG&E's Payment Option No. 3 is not a viable option for small gas-fueled cogenerators.

We have three measures for assessing the IERs in PG&E's interim SO 4. First are the IERs shown in Table 14, which are those adopted in D.83-12-068 in PG&E's most recent general rate case. We determined at that time that reasonable IERs for PG&E after Helms and both Diablo Canyon nuclear units are operational range from 13,303 British thermal units per kilowatt-hour (Btu/kWh) to 8,489 Btu/kWh, depending on the time of day and season, with an annual average of 10,356 Btu/kWh. This is 14 percent higher than the IER of 9050 Btu/kWh for 1985 contained in PG&E's Payment Option No. 3.

TABLE 13

Payment Option No. 3

QF Incremental Energy Rates (Annual Average)
(Btu/kWh)

Year	Oil Based at Generation Level			Gas Based at Generation Level		
	PG&E*	SCE	SDG&E	PG&E*	SCE	SDG&E
1983	—	9400	—	—	9729	—
1984	8496	8930	9100	9000	9243	9519
1985	8543	8920	8600	9050	9232	8996
1986	8345	8870	7700	8840	9180	8054
1987	8354	8900	7700	8850	9212	8054
1988	8458	8900	7700	8960	9212	8045
1989	8326	9030	8200	8820	9346	8577
1990	8062	8880	8200	8540	9191	8577
1991	8062	8750	8200	8540	9056	8577
1992	8062	8750	8200	8540	9056	8577
1993	8062	8750	8200	8540	9056	8577
1994	8062	8750	8200	8540	9056	8577
1995	8062	8750	8200	8540	9056	8577
1996	8062	8750	8200	8540	9056	8577
1997	8062	8750	8200	8540	9056	8577
1998	—	—	8200	—	—	8577

* Curtailment Option A.

(1) O&M expenses included.

(2) O&M expenses not included.

TABLE 14

Pacific Gas and Electric Company
Adopted Incremental Energy Rates with
Various Major Resource Configurations*
Test Year 1984
(Btu/kWh)

Costing Period	Without Helms Without Diablo 1 Without Diablo 2	With Helms Without Diablo 1 Without Diablo 2	With Helms With Diablo 1 Without Diablo 2
Period A:			
On-Peak	13,674	14,086	12,168
Partial-Peak	12,665	13,382	11,369
Off-Peak	10,119	10,499	9,429
Seasonal Average	11,538	12,031	10,515
Period B:			
On-Peak	15,410	16,320	14,224
Partial-Peak	14,730	15,689	13,552
Off-Peak	11,353	11,625	10,261
Seasonal Average	13,089	13,692	11,954
Annual	12,427	12,982	11,340

Costing Period	With Helms With Diablo 1 With Diablo 2
Period A:	
On-Peak	10,692
Partial-Peak	9,923
Off-Peak	8,489
Seasonal Average	9,322
Period B:	
On-Peak	13,303
Partial-Peak	12,694
Off-Peak	9,468
Seasonal Average	11,122
Annual	10,356

* Based on weighted average hydro conditions; includes generation-level losses to the point of interconnection with the transmission grid.

Because the IERs in PG&E's Payment Option No. 3 are not time-differentiated, they do not convey a price incentive to cogenerators to schedule operations with emphasis on the time periods when electricity is of the most value to PG&E. We note, that, under SO 1, non-time differentiated capacity payments are half the average achievable if a QF accepts time-differenciated payments. While the value of energy does not vary as much with time and season as does capacity, we cannot conclude at this time that the difference between PG&E's Payment Option No. 3 and the IERs adopted in PG&E's general rate case is unreasonable.

Another useful measure is a comparison of the amount of non-biomass cogeneration which has signed contracts with PG&E and SCE since Payment Option No. 3 of interim SO 4 was negotiated and approved. In Table 15, this comparison is made. PG&E has signed over twice as many contracts for cogeneration projects less than 50 MW than has SCE, with over four times the total capacity. We recognize that this does not indicate directly whether the IERs in Payment Option No. 3 of PG&E's interim SO 4 are reasonably accurate. However, it is clear that they have not prevented many small gas-fired cogenerators from signing acceptable contracts with PG&E and proceeding with their projects.

TABLE 15

Capacity of Cogeneration Projects(1)
Which Signed Contracts
After September 1983

Megawatts (Number of Projects)

	Size of Project		
	0-25	25-50	Over 50
PG&E:			
Operational	72(17)	0	0
Non-Operational	151(29)	588(13)	831(9)
SCE:			
Operational	17(8)	0	0
Non-Operational	3(9)	172(6)	1,430(6)

(1) Fueled by other than solid waste/biomass.

Finally, as we discussed in the prior section, the unexpected number of QF projects which have signed contracts since the negotiating session in June 1983 would tend to drive down the IERs which are appropriate for future contracts.

Based on the information at hand, we cannot conclude that PG&E's IERs present an impediment to cogeneration development significant enough to warrant increases at this time, nor that the IERs offered by any of the utilities in interim SO 4 should be decreased to protect ratepayers.

PG&E's IERs will be addressed in 1985 and 1986 in two proceedings—the additional long-run proceedings and PG&E's 1987 general rate case. We hope that a more consistent approach will be developed between these two proceedings so that any adopted results will be directly comparable.

IV. Conclusion

We find ourselves in the unenviable position of reconciling, on scant information, two worthy but competing goals. First, there is our omnipresent duty to protect the interests of California electric ratepayers, ensuring that they receive reliable, safe utility service at the lowest reasonable rates. Then there is the more recent but also important goal of fostering the development of diverse, third-party electric generating resources, the QF industry. Our action is taken due to our concern that we may have, in pursuing the latter, neglected the first. This is an unfortunate development in that we fully expect QF development will ultimately benefit the electric ratepayer with improved system reliability, greater diversity of resources and rate stability. To ensure that both goals are pursued to what we hope will be a mutually compatible end, we today take pause to reevaluate one aspect of our QF program. Our hope is that all parties—utilities, QFs and their trade associations, our Staff and other intervenors—will participate in the course of action set forth in this order and help guide us to a positive, successful resolution of the concerns we here confront. While that resolution is as yet uncertain, we are confident that we are by today's order taking the best next step available to us to place QF development and integration on the right track.

Findings of Fact

1. The Commission has authorized utilities to execute contracts with Qualifying Facilities (QFs) based upon long-run avoided costs as reflected in long-term capacity and energy payments on the ground that such contracts served the public interest. These contracts are referred to as interim Standard Offer No. 4 (SO 4).

2. The terms and conditions of interim SO 4 were to be available to QFs pending the adoption of "final" SO 4 terms and conditions. The final SO 4 contract is being developed in an as yet ongoing proceeding.

3. Interim SO 4 offered three payment options to QFs. These options were to be available for a period of one year, except for Payment Option No. 1, which was to be in effect for up to two years.

4. By Decision 84-08-035, all payment options under interim SO 4 were extended until further order.

5. By Decision 84-10-098, the availability of Payment Option 3 of SO 4 was suspended as to projects greater than 50 megawatts for QFs seeking contracts with Pacific Gas & Electric Co. (PG&E) on the ground that an unexpectedly large response to this offer was being experienced, raising the danger that PG&E might be required to contract for capacity either that PG&E did not need or at a price in excess of its value to PG&E.

6. By Decision 84-12-027, the above suspension was continued to January 16, 1985, in order to coordinate further actions with an interconnection priority procedure.

7. By Decision 85-01-038, an interconnection priortiy procedure (IPP) was adopted; the IPP required, inter alia, that PG&E, Southern California Edison Co. (SCE) and San Diego Gas & Electric Co. (SDG&E) compile information of QF development activities in their service territories.

8. By Decision 85-01-040, the suspension of Payment Option No. 3 of interim SO 4 was again continued, this time through April 17, 1985, to provide time during which PG&E, SCE and

SDG&E could compile the information required by the IPP. Those utilities have done so and have filed their data and findings with the Commission.

9. By Decision 85-02-069, the availability of Payment Option No. 3 of SO 4 was suspended for SCE under terms similar to those applied in the case of PG&E; that suspension was imposed through April 17, 1985.

10. The December 31, 1984, Quarterly Status Reports filed by the utilities pursuant to prior Commission order show that PG&E, SCE and SDG&E have contracts with total nameplate capacity of 6593, 4111 and 125 megawatts, respectively. Additional projects could add 4542, 2474 and 188 megawatts, respectively, to those totals.

11. Under our asssumption of low QF development (the "30 percent scenario" shown in Appendix A, p. A-23), PG&E's reserve margin through 1989 is at least 31 percent.

12. Under our assumption of intermediate QF development (the "50 percent scenario" shown in Appendix A, p. A-11), SCE's reserve margin through 1989 is at least 20 percent.

13. There is a low probability that PG&E will experience unreasonably low reserve margins or capacity shortages through 1989. There is a higher, but still low, probability that SCE will experience capacity shortages over that same period; it is unlikely that, to avoid such shortages, SCE will need only 158 megawatts of additional QF capacity through 1994.

14. The low probabilities that PG&E and SCE will experience capacity shortages indicate that the capacity payments in interim SO 4 overestimate the value of new QF capacity to the utilities and their ratepayers.

15. Capacity payments made by SDG&E to QFs under Standard Offers Nos. 1 and 2 were reduced in Decision 83-12-065, the utility's last general rate case, in order to reflect SDG&E's forecasted need for additional QF capacity. Since the value of QF capacity under interim SO 4 was based upon those values as set forth in Standard Offers Nos. 1 and 2, the lower valuation for QF capacity under those standard offers would

indicate that a lower value should be used in its interim SO 4 as well.

16. Utility reserve margins provide a measure of the need a utility would have for additional generating capacity and, as a result, also provide a reasonable standard by which to measure the value of additional QF capacity.

17. As shown in Table 6, natural gas rates in California electric utilities have fallen since the time energy payments to QFs under interim SO 4 were adopted.

18. As shown in Table 5, real incremental natural gas prices to California distribution utilities have fallen since the time energy payments to QFs under interim SO 4 were adopted.

19. Energy payments to QFs under Payment Options Nos. 1 and 2 of interim SO 4 are based upon steam electric natural gas rates which were forecasted to increase.

20. The energy payments in Payment Options Nos. 1 and 2 of interim SO 4 overestimate the utility's avoided energy costs by assuming escalating marginal fuel prices.

21. A ten percent (10%) reduction in energy payments to QFs under Payment Options Nos. 1 and 2 of interim SO 4 reasonably reflects changes in the utilities' forecasted marginal fuel prices which have occurred since the Commission's adoption of interim SO 4.

22. Under the present terms of interim SO 4, there is a reasonable probability that the utilities and their ratepayers are paying too great a price for QF electricity.

23. A second negotiating conference would invest this proceeding with further delay and thereby would serve no useful purpose.

24. Assuming the Commission elects to make available a revised interim SO 4, permitting those QFs signing interim SO 4 under revised terms and conditions to switch to the terms and conditions of a final SO 4, when available, will provide some assurance to QFs that their interests will not be prejudiced by the revisions.

Conclusions of Law

1. It is reasonable to suspend the availability of interim SO 4 for QFs seeking to execute contracts with SCE, PG&E, and SDG&E until there is available an SO 4 contract with final terms and conditions. In lieu of a suspension for Payment Options Nos. 1 and 2 and Payment Option No. 3 for QF projects less than 50 megawatts, it would be reasonable to reduce: (1) the capacity payments offered under interim SO 4; and (2) the energy payments offered under Payment Options Nos. 1 and 2 of interim SO 4; and, to permit QFs to execute interim SO 4 contracts under these revised terms and conditions pending the availability of a final SO 4 contract.

2. Interested parties should be permitted to comment on whether suspending interim SO 4 or making available a revised interim SO 4, execpt for Payment Option No. 3 for projects over 50 megawatts, is the more desirable regulatory course of action pending the adoption of a final SO 4.

3. A second negotiating conference should not be held.

4. A workshop should be held to further explain to interested parties the manner and basis of the revisions to SO 4 proposed by the Commission.

5. Assuming the Commission elects to make available a revised interim SO 4, permitting those QFs signing interim SO 4 contracts under the revised terms and conditions to switch to the terms and conditions of a final SO 4, when available, is reasonable.

INTERIM ORDER

THEREFORE, IT IS ORDERED that:

1. Interim Standard Offer No. 4, as adopted by Decision 83-09-054, is hereby suspended for Southern California Edison Co., Pacific Gas & Electric Co. and San Diego Gas & Electric Co. With respect to projects proposed by Qualifying Facilities (QFs) under Payment Option No. 3 of interim Standard Offer No. 4 which are larger than 50 megawatts, the suspension shall be for an indefinite period. With respect to all other projects proposed by

QFS under interim Standard Offer No. 4, the suspension shall be effective until further order of the Commission.

2. Staff shall conduct a workshop on May 3, 1985, at which it shall explain and answer questions regarding the proposed revisions to energy payments under Payment Options Nos. 1 and 2 of interim Standard Offer No. 4 and capacity payments under all payment options of interim Standard Offer No. 4 as set forth in this decision.

3. Interested parties shall file written comments no later than May 10, 1985, stating their preference for the indefinite suspension of the entirety of interim Standard Offer No. 4 or the implementation of the subject revisions of energy and capacity payments under said Standard Offer.

This order is effective today.

Dated April 17, 1985, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
WILLIAM T. BAGLEY
FREDERICK R. DUDA
Commissioners

I abstain.
/s/ PRISCILLA C. GREW
Commissioner

APPENDIX A

CALCULATION OF VALUE OF ADDITIONAL QF CAPACITY

SOUTHERN CALIFORNIA EDISON
FIRM CAPACITY PRICE SCHEDULE
(LEVELIZED $/KW-YEAR)
FOR THE FIRST 1000 MW OF ADDITIONAL QF POWER

Scenario 1: Assume 50% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	73	77	94	107	117	125	131
1986	86	83	102	115	126	134	140
1987	81	88	108	123	134	143	150
1988	66	96	118	133	145	155	162
1989	80	112	132	148	160	170	178
1990	104	128	146	162	176	186	194
1991	122	140	159	176	190	201	210

Scenario 2: Assume 80% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	73	67	79	94	105	113	119
1986	83	65	84	100	112	121	127
1987	68	63	89	106	119	128	135
1988	51	68	98	116	130	139	147
1989	47	83	113	131	145	155	163
1990	69	104	131	149	163	174	182
1991	85	123	148	166	181	192	201

Scenario 3: Assume 30% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	74	87	102	114	123	131	137
1986	88	96	111	123	133	141	147
1987	90	102	118	131	142	151	158
1988	90	110	127	141	153	162	169
1989	103	121	138	153	165	175	183
1990	116	131	149	164	178	188	196
1991	125	141	159	176	190	201	210

Average Values from Scenarios 1, 2 and 3

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	74	77	92	105	115	123	129
1986	85	81	99	113	124	132	138
1987	80	84	105	120	132	141	148
1988	69	92	114	130	142	152	159
1989	77	105	128	144	157	167	174
1990	97	121	142	159	172	183	191
1991	111	135	155	173	187	198	207

WORK PAPERS

SOUTHERN CALIFORNIA EDISON COMPANY

General Assumptions

1. Peak-Availability of QFs

   a. All firm QFs will have 80% average peak availability.

   b. As-available QFs will have 20% average peak availability.

2. Time Distribution of QFs

   a. ⅓ of materializing QFs come on line 3 years after signing the contract.

   b. ⅔ of materializing QFs are on line 4 years after signing the contract.

   c. All materializing QFs are on line 5 years after signing the contract.

3. Value of Capacity

   a. Up to 20% reserve margin, QF capacity is worth full gas turbine with the utility.

   b. At over 35% reserve margin, the value of additional QF capacity is zero.

   c. Between 20-35% the value of QF capacity declines linearly from 1 to 0.

4. Capacity Cost

   a. Combustion turbine cost, inflation rate and discount rate same as adopted in the utility's last general rate case.

SOUTHERN CALIFORNIA EDISON COMPANY

QF Capacity Signed as of 12-31-84(a)

CALCULATION OF EFFECTIVE CAPACITY

	(MW)
Total QF Capacity Signed (Nameplate)	=4110
Total Effective QF Capacity	
Already Operational QFs (Nameplate)	= 647
Out of it, wind + small hydro (Nameplate)	= 293
Other	= 354
Total effective operational QF capacity = (293 × .2) + 354	= 413
Not yet on line = 2831 − 413	=2418
Total committed effective capacity:	
If all QFs come on line = 413 + 2418	=2831
If 80% QFs come on line = 413 + (.8 × 2418)	=2347
If 50% QFs come on line = 413 + (.5 × 2418)	=1622
If 30% QFs come on line = 413 + (.3 × 2418)	=1138

(a) Sources:

1. SCE December 1984 Report on QF Power
2. Table 1 and 2 accompanying SCE motion of January 1985

SOUTHERN CALIFORNIA EDISON COMPANY

TIME DISTRIBUTION OF SIGNED QF CAPACITY(a)

	(MW)
Effective QF capacity signed prior to 12-31-82	= 666
Effective QF capacity signed during 1983	= 237
Effective QF capacity signed during 1984	=1928
Total	=2831

Time Distribution of QF Power

(MW)

Year	If all QFs materialize	If 80% materialize	If 50%	If 30%
1985.....	413*+84 = 497	413+67 = 460	413+42 = 455	413+25 = 438
1986.....	413+2(84)+79 = 660	413+198 = 611	413+124 = 537	413+74 = 487
1987.....	413+253+2(79)+643=1467	413+843 =1256	413+527 = 940	413+316= 729
1988.....	666+3(79)+2(643) =2189	413+1421=1834	413+1095=1508	413+533= 946
1989.....	666+237+1928 =2831	413+1936=2349	413+1210=1623	413+726=1139

* Already on line

(a) Source: SCE Quarterly Reports on Cogeneration and Small Power

SOUTHERN CALIFORNIA EDISON COMPANY

OF POWER(a) IN THE RESOURCE PLAN(b)

(MW)

Year	Cogen	Small Hydro	Biomass	Wind	Solar	Geother-mal	Fuel Cells	Total QFs
1984	28(13)	6	2	53	15	32	0	123
1985	199(13)	23	31	101	71	159(5)	0	566
1986	323(13)	25	123	118	97	216(5)	0	884
1987	358(13)	28	179	132	121	258(14)	0	1049
1988	393(13)	32	227	148	121	283(14)	0	1177
1989	728(13)	35	242	163	129(8)	308(14)	0	1570
1990	1013(13)	36	257	166	129(8)	332(14)	0	1826
1991	1048(13)	36	272	169	154(8)	357(14)	0	2001
1992	1083(13)	37	287	172	179(8)	382(14)	8(8)	2105
1993	1368(13)	37	302	175	204(8)	407(14)	30(30)	2458
1994	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
1995	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
1996	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
1997	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
1998	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
1999	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562
2000	1403(13)	38	317	178	229(8)	432(14)	30(30)	2562

(a) Figures in parentheses show non-QF generation

(b) SCE Fall 1984 Resource Plan

SOUTHERN CALIFORNIA EDISON COMPANY

COMMITTED AND NONCOMMITTED RESOURCES

(MW)

Year	Total(a) Resources	QF(a) Power	Non-QF Resources	Non-QF(b) Non-Committed	Non-QF Committed Resources
(1)	(2)	(3)	(4) =(2)-(3)	(5)	(6) (6)=(4)-(5)
1985	17,654	566	17,088	0	17,088
1986	18,095	884	17,211	0	17,211
1987	18,377	1,049	17,328	0	17,328
1988	18,694	1,177	17,517	0	17,517
1989	19,010	1,570	17,440	0	17,440
1990	19,183	1,826	17,357	0	17,357
1991	19,582	2,001	17,581	0	17,581
1992	19,833	2,105	17,728	0	17,728
1993	20,284	2,458	17,826	0	17,826
1994	20,695	2,562	18,133	215	17,918
1995	21,145	2,562	18,583	665	17,918
1996	21,502	2,562	18,940	1,530	17,410
1997	21,882	2,562	19,320	2,230	17,090
1998	22,336	2,562	19,774	2,830	16,944
1999	22,662	2,562	20,100	3,796	16,304
2000	23,042	2,562	20,480	4,846	15,634
2001	23,352	2,562	20,790	5,446	15,344
2002	23,932	2,562	21,370	6,026	15,344
2003	24,132	2,562	21,570	6,576	14,994
2004	24,712	2,562	22,150	7,156	14,994

(a) Source: Fall '84 Resource Plan

(b) Resource additions expected from SCE hydro, PNW/PSW purchases and Pacific intertie expansion are treated as committed because of their low cost.

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SOUTHERN CALIFORNIA EDISON

SCENARIO 1: 50% OF QFS (NOT YET OPERATING) MATERIALIZE, WITH 1000 MW ADDITIONAL QFS

Year (1)	SCE Committed Resources (2)	QF Resources (3)	Total Committed Resources (4)=2+3	Projected Loads (5)	Reserve Margin (6)
1985	17088	455	17543	14420	22
1986	17211	537	17748	14730	20
1987	17328	940	18268	14960	22
1988	17517	1508	19025	15320	24
1989	17440	1623	19063	15660	22
1990	17357	1623	18980	16030	18
1991	17581	1623	19204	16390	17
1992	17728	1623	19351	16760	15
1993	17826	1623	19449	17140	13
1994	17918	1623	19541	17520	12
1995	17918	1623	19541	17880	9
1996	17410	1623	19033	18220	4
1997	17090	1623	18713	18560	1
1998	16944	1623	18567	18890	-2
1999	16304	1623	17927	19220	-7
2000	15634	1623	17257	19540	-12
2001	15344	1623	16967	19880	-15
2002	15344	1623	16967	20200	-16
2003	14994	1623	16617	20540	-19
2004	14994	1623	16617	20880	-20

Reserve Margin With 1000MW More QFs (7)	Average Reserve Margin (8)	Adjustment Factor (9)	Annualized Combustion Turbine Cost (10)	Present Worth Factor (11)	Adjusted Present Worth of Combustion Turbine (12)=9*10*11
22	21.7	0.89	83	1	73
20	20.5	0.96	89	0.8696	74
22	22.1	0.86	95	0.7561	61
26	25.3	0.64	102	0.6575	43
26	23.9	0.74	109	0.5718	46
25	21.5	0.89	116	0.4972	52
23	20.2	0.98	125	0.4323	53
21	18.4	1.00	133	0.3759	50
19	16.4	1.00	143	0.3269	47
17	14.4	1.00	153	0.2843	43
15	12.1	1.00	163	0.2472	40
10	7.2	1.00	175	0.2149	38
6	3.5	1.00	187	0.1869	35
4	0.9	1.00	200	0.1625	33
-2	-4.1	1.00	214	0.1413	30
-7	-9.1	1.00	229	0.1229	28
-10	-12.1	1.00	245	0.1069	26
-11	-13.5	1.00	262	0.0929	24
-14	-16.7	1.00	281	0.0808	23
-16	-18.0	1.00	300	0.0703	21
		1.00	321	0.0611	20
		1.00	344	0.0531	18
		1.00	368	0.0462	17
		1.00	393	0.0402	16
		1.00	421	0.0349	15
		1.00	450	0.0304	14
		1.00	482	0.0264	13
		1.00	516	0.0230	12
		1.00	552	0.0200	11
		1.00	590	0.0174	10
		1.00	632	0.0151	10
		1.00	676	0.0131	9
		1.00	723	0.0114	8
		1.00	774	0.0099	8
		1.00	828	0.0086	7
		1	886	0.0075	7

SOUTHERN CALIFORNIA EDISON

PRESENT FIRM CAPACITY PRICE SCHEDULES

FOR STANDARD OFFER #2:

CAPACITY PRICE OFFERS—FIRM ($/kW/Year)

Initial Operation Date Southern California Edison (SCE)	Duration of Contract (Years)					
	1	5	10	15	20	30
1985	83	92	105	116	125	138
1986	88	99	112	124	133	146
1987	94	105	120	132	143	155
1988	100	113	128	141	153	165
1989	107	121	137	151	164	175

FOR STANDARD OFFER #4:

Year of Initial Delivery	$/kW/Year Contract Term (Years)						
	1	5	10	15	20	25	30
1983	70	80	92	105	114	121	127
1984	76	86	100	113	123	131	137
1985	81	93	108	122	132	141	147
1986	87	100	117	131	143	152	158
1987	94	107	127	142	154	163	170
1988	101	117	137	153	166	176	184

PACIFIC GAS AND ELECTRIC
FIRM CAPACITY PRICE SCHEDULE
(LEVELIZED $/KW-YEAR)
FOR THE FIRST 1000 MW OF ADDITIONAL QF POWER

Scenario 1: Assume 30% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	20	7	19	44	59	70	77
1986	9	2	26	52	68	79	87
1987	0	1	38	64	81	92	100
1988	0	8	53	80	96	108	117
1989	0	21	72	98	115	127	136
1990	0	43	93	119	137	149	159
1991	5	75	119	144	162	175	185

Scenario 2: Assume 50% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	20	6	11	35	51	62	69
1986	6	2	15	42	59	70	78
1987	0	0	25	53	70	82	91
1988	0	1	39	67	85	97	106
1989	0	8	55	83	102	114	124
1990	0	21	74	103	121	135	144
1991	0	42	97	125	144	158	168

Scenario 3: Assume 80% of the Signed QFs (not yet on line) Materialize

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	19	5	4	24	40	51	59
1986	1	0	4	29	47	58	66
1987	0	0	10	39	57	69	78
1988	0	0	19	51	69	82	91
1989	0	0	33	64	84	97	107
1990	0	3	49	81	101	115	125
1991	0	11	68	100	121	135	146

Average Values from Scenarios 1, 2 and 3

Year Operation Begins	Number of Years of Firm Delivery						
	1	5	10	15	20	25	30
1985	20	6	10	34	50	60	68
1986	6	1	13	41	57	68	76
1987	0	0	23	51	68	80	89
1988	0	0	36	65	83	95	104
1989	0	5	52	81	99	112	121
1990	0	17	70	99	118	132	141
1991	0	37	93	122	141	155	165

Workpapers

Pacific Gas & Electric Company

General Assumptions

1. Peak-Availability of QFs

   a. All firm QFs have 80% average availability.

   b. Average peak availability for PG&E as-available wind and hydro QFs is 20% and 22% respectively. Cogeneration and solid waste QFs have 30% average peak availability.

2. Time Distribution of QFs

   a. ⅓ of materializing QFs come on line 3 years after signing the contract.

   b. ⅔ of materializing QFs are on line 4 years after signing the contract.

   c. All materializing QFs are on line 5 years after signing the contract.

3. Value of Capacity

   a. Up to 20% reserve margin, QF capacity is worth full gas turbine to the utility.

   b. At 35% reserve margin or above, the value of additional QF capacity is zero.

   c. Between 20-35% the value of QF capacity declines linearly from 1 to 0.

4. Capacity Cost

   a. Combustion turbine cost, inflation rate and discount rate same as adopted in the utility's last general rate case.

Pacific Gas and Electric Company

	MW
Total QF Capacity Signed (Nameplate) as of 12.31.84	=6,593
Firm	=3,550
As-Delivered	=2,992
Energy only	= 38
Parallel Generation	= 13
Effective Capacity	
Firm	=3,550
As-Delivered	=(149×.3)+(549×.22)+(.2×2295) =45+120+459 =624
Total Effective Peak Capacity	=3,550+624 =4,174
Already Operational (Nameplate)	=942
Out of if, wind+hydro	=379
Other	=563
Operational Effective Peak Capacity	=(379×.2)+563=640 approximately
Total Effective Peak Capacity not on line yet	=4,174−640 =3,534
Total effective peak capacity:	
if all QFs come on line	=640+3,534=4,174
if 80% QFs come on line	=640+(.8×3,524)=3,467 MW
if 50% QFs come on line	=640+(.5×3,524)=2,407 MW
if 30% QFs come on line	=640+(.3×3,524=1,700 MW

Pacific Gas & Electric Company

Time Distribution of QF Power

Effective capacity signed prior(1) to 12.31.82 ..... =814 MW
Effective capacity signed during(2) 1983 ..... =880
Effective capacity signed during(3) 1984 ..... =2,480
Total effective capacity as of 12.31.84 ..... =4,174

Time Distribution of QF Power

Year	If all materialize		If 80%	If 30%	If 50%
1985.....	640(4)+58=698		640+(.8x58)=686	657	669
1986.....	640 +2(58)+293	=1,049	640+(.8x409)=967	763	845
1987.....	640 +174+2(293)+827	=2,227	640+(.8x1,587)=1,190	1,116	1,433
1988.....	640 +174+880+2(827)	=3,348	640+(.8x2,708)=2,806	1,452	1,994
1989.....	640 +174+880+2,480	=4,174	640+(.8x3,534)=3,467	1,700	2,407

(1) PG&E Quarterly Report 12.31.82
(2) PG&E Quarterly Report 12.31.83
(3) PG&E Quarterly Report 12.31.84
(4) Already operational

Pacific Gas and Electric Company
QFs in the Resource Plan(a)

Year	Small Hydro	Cogeneration + Solid Waste	Geothermal	Wind and Solar	Yearly Total	Cumulative Total
As of 8-31-83	17(b)	331(179)	0	13(2.5)	179.5	179.5
1984 ..	7.5	82	80	11	180.5	360.0
1985 ..	7.4	103	0	30	140.4	500.4
1986 ..	7.1	427	0	15	449.1	949.5
1987 ..	5.3	346	0	22	373.3	1,322.8
1988 ..	4.0	79	0	45	128.0	1,450.8
1989 ..	4.0	75	0	31	110.0	1,560.8
1990 ..	4.0	75	0	33	112.0	1,672.8
1991 ..	4.0	69	0	29	102.0	1,774.8
1992 ..	4.0	68	0	34	101.0	1,875.8
1993 ..	4.0	38	0	40	82.0	1,957.8
1994 ..	4.0	38	0	55	97.0	2,054.8
1995 ..	4.0	38	0	20	62.0	2,116.8
1996 ..	4.0	50	0	25	79.0	2,195.8
1997 ..	4.0	50	0	25	79.0	2,274.8
1998 ..	4.0	50	0	24	78.0	2,352.8
1999 ..	4.0	50	0	22	76.0	2,428.8
2000 ..	4.0	50	0	21	75.0	2,503.8
2001 ..	4.0	50	0	30	84.0	2,587.8
2002 ..	4.0	50	0	28	82.0	2,669.8
2003 ..	4.0	50	0	27	81.0	2,750.8
2004 ..	4.0	50	0	24	78.0	2,828.8
Total...	112.3	2,035	80	601.5	2,828.8	2,828.8

(a) PG&E's Long-Term Plan, May 1984.
(b) Taken from 4th Quarter 1983 Report (85 × .2) = 17 MW.

PACIFIC GAS AND ELECTRIC COMPANY

NON-COMMITTED(a) NON-QF RESOURCES(b)

Year	Geo-thermal	Refurbish-ment	PG&E Unspeci-fied	Other Utility Uniden-tified	Yearly Addi-tion	Cumula-tive Total Addi-tion
1985	0	0	0	0	0	0
1986	0	0	0	0	0	0
1987	0	0	0	0	0	0
1988	0	0	0	0	0	0
1989	110	0	0	0	110	110
1990	110	214	0	0	324	434
1991	165	0	0	100	265	699
1992	110	0	0	0	110	809
1993	0	123	0	200	323	1,132
1994	0	234	0	0	234	1,366
1995	0	232	0	100	332	1,698
1996	0	326	0	100	426	2,124
1997	0	268	0	0	268	2,392
1998	0	326	250	250	826	3,218
1999	0	163	250	0	413	3,631
2000	0	163	500	150	813	4,444
2001	0	325	500	0	825	5,269
2002	0	325	500	0	825	6,094
2003	0	338	500	0	838	6,932
2004	0	338	500	0	838	7,770
Total ...	495	3,375	3,000	900	7,770	7,770

(a) Sources: May 1984 Long Term Resources plan and CFM-V filing.

(b) Imports of 245 MW and all projected hydro additions are treated as committed because of their possible low cost.

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PACIFIC GAS AND ELECTRIC

SCENARIO 1: 30% OF QFS (NOT YET ON LINE) MATERIALIZE, WITH 1000MW ADDITIONAL QFS

Year (1)	PG&E Committed Resources (2)	QF Resources (3)	Total Committed Resources (4)=2+3	Projected Loads (5)	Reserve Margin (6)
1985	19729	657	20386	15523	31
1986	20140	763	20903	15667	33
1987	20362	1116	21478	15883	35
1988	20620	1452	22072	16074	37
1989	20696	1700	22396	16254	38
1990	20536	1700	22236	16483	35
1991	20326	1700	22026	16770	31
1992	19970	1700	21670	17083	27
1993	19850	1700	21550	17378	24
1994	19619	1700	21319	17685	21
1995	19428	1700	21128	17961	18
1996	19105	1700	20805	18284	14
1997	18840	1700	20540	18684	10
1998	18517	1700	20217	19087	6
1999	18357	1700	20057	19495	3
2000	18194	1700	19894	19889	0
2001	17869	1700	19569	20407	−4
2002	17544	1700	19244	20892	−8
2003	17206	1700	18906	21405	−12
2004	16868	1700	18568	21931	−15

Reserve Margin With 1000MW More QFs (7)	Average Reserve Margin (8)	Adjustment Factor (9)	Annualized Combustion Turbine Cost (10)	Present Worth Factor (11)	Adjusted Present Worth of Combustion Turbine (12)=9*10*11
31	31.3	0.24	84	1	20
33	33.4	0.10	91	0.8696	8
35	35.2	0.00	98	0.7561	0
39	38.4	0.00	106	0.6575	0
42	39.8	0.00	115	0.5718	0
41	37.9	0.00	124	0.4972	0
37	34.3	0.04	132	0.4323	2
33	29.8	0.34	142	0.3759	18
30	26.9	0.54	152	0.3269	27
26	23.4	0.77	162	0.2843	36
23	20.4	0.97	174	0.2472	42
19	16.5	1.00	186	0.2149	40
15	12.6	1.00	199	0.1869	37
11	8.5	1.00	213	0.1625	35
8	5.4	1.00	228	0.1413	32
5	2.5	1.00	243	0.1229	30
1	−1.7	1.00	261	0.1069	28
−3	−5.5	1.00	279	0.0929	26
−7	−9.3	1.00	298	0.0808	24
−11	−13.1	1.00	319	0.0703	22
		1.00	342	0.0611	21
		1.00	365	0.0531	19
		1.00	391	0.0462	18
		1.00	418	0.0402	17
		1.00	448	0.0349	16
		1.00	479	0.0304	15
		1.00	513	0.0264	14
		1.00	548	0.0230	13
		1.00	587	0.0200	12
		1.00	628	0.0174	11
		1.00	672	0.0151	10
		1.00	719	0.0131	9
		1.00	769	0.0114	9
		1.00	823	0.0099	8
		1.00	881	0.0086	8
		1	942	0.0075	7

PACIFIC GAS AND ELECTRIC

PRESENT FIRM CAPACITY PRICE SCHEDULES

For Standard Offer #2:

Firm Capacity Price Schedule
(Levelized $/kW-year)

Actual Operation Date (Year)	Term of Agreement																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
1983	72	111	96	88	84	85	88	91	93	96	98	100	102	104	106	115	122	128
1984	156	111	95	88	89	92	95	98	100	103	105	108	110	112	114	124	131	137
1985	60	58	59	66	73	79	84	88	92	95	99	102	104	107	110	121*	127*	135
1986	56	58	69	78	85	90	95	99	103	106	110	113	116	118	121	132	141	148
1987	61	77	88	95	101	105	109	113	117	120	124	127	130	132	135	147	156	163
1988	96	104	110	115*	119	122	126	129	133	136	139	142	145	148	151	163	173	180

For Standard Offer #4

Firm Capacity Price Schedule
(Levelized $/kW-year)

Firm Capacity Availability Date (Year)	Number of Years of Firm Capacity Delivery																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
1982	65	68	70	72	75	77	79	81	84	86	88	90	91	93	95	103	109	113
1983	70	73	75	78	80	83	85	88	90	92	94	96	98	100	102	110	117	122
1984	76	78	81	84	86	89	92	94	97	99	101	103	106	108	110	118	125	130
1985	81	84	87	90	93	96	99	101	104	106	109	111	113	115	118	127	134	140
1986	88	91	94	97	100	103	106	109	112	114	117	119	122	124	126	136	144	150
1987	95	98	101	105	108	111	114	117	120	123	125	128	130	133	135	146	154	160

APPENDIX B

10-Apr-85

SOUTHERN CALIFORNIA EDISON COMPANY

Cogeneration and Small Power Production

Cancelled Contracts and Letters of Intent
As of December 31, 1984

Project/ Development	Project Capacity (KW)	Technology	Comments
Acurex	12,000	Solar	Contract
California Alternate Power Sources	11,250	Wind	Contract
California Federal	2,400	Cogeneration	Letter of Intent
Carson Bio-Energy Company	2,100	Biomass	Letter of Intent
Central Plants— Irwindale	250	Biomass	Contract
Energy Recycling and Storage	100	Cogeneration	Letter of Intent
Hamilton Standard	20,000	Wind	Letter of Intent
Reichold Energy Corporation	1,300	Cogeneration	Letter of Intent
Shell California Production	150,000	Cogeneration	Contract
Solar World	3,900	Wind	Letter of Intent
Stinnet Oil	200	Cogeneration	Contract
United Ethanol of Delano	49,000	Biomass	Letter of Intent

APPENDIX F

Decision 86-10-038 October 16, 1986

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983, and August 2, 1983)

Application 82-04-46 (Filed April 21, 1982; amended May 12, 1982, July 11, 1983, and August 10, 1983)

Application 82-04-47 (Filed April 21, 1982; amended July 11, 1983, and August 2, 1983)

Application 82-03-26 (Filed March 8, 1982)

Application 82-03-37 (Filed March 8, 1982)

Application 82-03-62 (Filed March 16, 1982)

Application 82-03-67 (Filed March 18, 1982)

Application 82-03-78 (Filed March 22, 1982)

Application 82-04-21 (Filed April 8, 1982)

Case 86-07-022 (Filed July 7, 1986)

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.

And Related Matters.

OPINION ON PETITIONS OF ULTRAPOWER, INC., GWF POWER SYSTEMS, THERMAL ENERGY DEVELOPMENT CORP., AND BASIC AMERICAN FOODS RELATING TO PRICE TABLES IN PACIFIC GAS AND ELECTRIC'S INTERIM STANDARD OFFER 4

This decision resolves a dispute regarding the interpretation of certain provisions in contracts under our interim Standard Offer 4 for purchase by Pacific Gas & Electrc Company (PG&E) of electrical output from qualifying facility (QF) projects. We determine that PG&E's firm capacity price schedule must be

extended to include those years in which the QF projects, consistent with the terms of their respective contracts, may come online. We decline to extend those schedules relating to as-available capacity and forecasted energy prices.

I. Procedural History

This matter reaches us via three petitions for modification. Each petition addresses solely or primarily Decision (D.) 83-09-054, in which we approved interim Standard Offer 4 and made it available to QFs. The petitioners (all developers of QF projects) are: Thermal Energy Development Corporation (Thermal); GWF Power Systems Company (GWF); and Ultrapower Incorporated (Ultrapower). Thermal filed its petition on August 6, 1986; the other two petitions filed on August 11. [1]

PG&E and our Public Staff both responded to the petitions.[2] Also, Basic American Foods (Basic) on September 12 filed a "Petition for Consolidation and Expedited Resolution of the Firm

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[1] A fourth petition, filed August 22, 1986, for modification of D.83-09-054 also concerns (among other issues) PG&E's firm capacity price schedule in interim Standard Offer 4. However, the petitioners (El Dorado Irrigation District, El Dorado County Water Agency, and SOFAR Management Authority) filed a request on September 8 to withdraw their petition. We note no opposition to this request and believe it should be granted.

Finally, on October 8, 1986, Dexzel, Inc. (Dexzel), filed its petition for modification of D.83-09-054 as the decision relates to PG&E's firm capacity price schedule. This petition comes after PG&E had filed its response to Thermal, GWF, and Ultrapower; however, our resolution in today's decision of those petitions renders Dexzel's petition moot.

[2] Article 2.5 (Rules 8.1 to 8.8) of our Rules of Practice and Procedure governs various types of responsive pleadings, including objections to petitions for modification. See Rule 8.1(a). PG&E's response, filed on September 12, was timely under Rule 8.3. Public Staff's response was delayed until September 15. Public Staff indicated that the delay resulted from mechanical difficulties with the central wordprocessing system after the Commission's move to its new offices. In light of these circumstances, we grant Public Staff's request to accept this late filing.

Capacity Price Issue" in this proceeding (Application (A.) 82-04-44 et al.). The petition asserts that Basic is the complainant in Case (C.) 86-07-022 versus PG&E; that the case concerns in major part the same issue regarding PG&E's firm capacity price schedule that is raised in these three petitions for modification; that PG&E has already filed its responsive pleading (namely, a motion to dismiss) in C.86-07-022; and that resolution of this issue requires only the application of legal principles to facts not materially disputed. Further, Basic sets forth various reasons, associated with the construction and certification of its proposed American I Cogeneration Project, why delay in resolving this issue would adversely affect the project. Basic concludes that administrative efficiency and its own need for expedited resolution would both be served by granting the requested consolidation.

On October 3, 1986, PG&E submitted its "Reply to Basic American Foods' Petition for Consolidation and . . . Opposition to [PG&E's] Motion to Dismiss" for filing in both the complaint proceeding and in A.82-04-44 et al. PG&E does not oppose Basic's request for consolidation and expedited resolution; in fact, PG&E "urges that all the interim SO #4 price escalation issues be resolved together in one forum." (*Id.*, p. 3.)

We agree with Basic's and PG&E's reasoning in this regard and direct the consolidation of C.86-07-022 with A.82-04-44 et al. for the limited purpose of addressing the firm capacity price issue raised in the complaint.[3]

II. Factual Background

Interim Standard Offer 4 was our first attempt to implement power purchase contracts based on utilities' *long-run* avoided costs. Unlike the short-run standard offers (such as Standard Offer 1) whose price terms yield payments to QFs that vary in response to the purchasing utility's short-run needs, any long-run

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[3] Basic's petition suggests that resolution of this issue may make further litigation in C.86-07-022 unnecessary. In any event, we direct that litigation of issues from the complaint other than the issue addressed here be confined to the complaint proceeding.

standard offer involves the same sort of planning (such as lengthy forecasts of the purchasing utility's resource mix and costs) that goes into a utility decision to build a new power plant.

Properly implemented, a long-run standard offer can reduce risks both to QFs (who receive relatively greater price certainty than under short-run contracts) and to utilities (who defer or avoid major commitments of capital and various risks associated with new plant construction). However, long-run avoided costs are more elusive than are utilities' short-run marginal costs. Pending resolution of the various long-run avoided cost methodological issues, we convened a negotiating conference with the objective of establishing a long-run standard offer that the utilities could file "at least on an interim basis" and that "will be supported by the parties" to this proceeding. (D.83-05-038, mimeo., p. 7.)

The negotiating conference, at which utilities, QFs, and Commission staff participated vigorously, resulted in a proposal that we ratified as interim Standard Offer 4. (See generally D.83-09-054, mimeo.) For present purposes, the crux of interim Standard Offer 4 is the price certainty provided to QFs by a series of energy and capacity price schedules. These schedules set forth payments for firm capacity, as-available capacity, and a series of three energy payment options, all depending on the individual QF's period of operation (on-line date and length of contract).

The problem that we address in today's decision is that the schedules we approved in D.83-09-054, and continued in effect by D.84-08-035 (where we allowed interim Standard Offer 4 to remain available), were not expressly extended to consider all the years when QFs signing the interim offer might come on-line. Absent such extension, those QFs coming on-line after 1987 would have limited or no price certainty as to their capacity payments, energy payments, or both. All of the petitioners request extension of PG&E's firm capacity price schedule; in addition, Ultrapower seeks extension of PG&E's as-delivered capacity and forecasted energy price schedules.

A. PG&E's Firm Capacity Price Schedule[4]

In many respects, the negotiations drew directly from the already existing Standard Offers 1, 2, and 3 in putting together interim Standard Offer 4. This is especially clear with respect to pricing of firm capacity. Thus, for example, PG&E's Third Amendment (filed July 11, 1983) to A.82-04-44 in which PG&E sought approval of interim Standard Offer 4, says bluntly, "Payment for firm capacity is identical to that of Option 2, Standard Offer 2.... QFs selling firm capacity receive capacity prices which are levelized over their contract terms." (*Id.*, Part B, p. 3.) PG&E is equally emphatic with respect to the methodology by which the utility is to value capacity on its system: "[A]voided customer shortage costs (often referred to as 'capacity') ... are estimated by using the annual fixed costs of a combustion turbine as a proxy." (*Id.*, Part B, pp. 1-2.) This accords exactly with our contemporaneous understanding when we approved interim Standard Offer 4. (See D.83-09-054, mimeo., pp. 23, 26.) Furthermore, it is also clear that PG&E's Standard Offer 2, at the time of the negotiation and approval of interim Standard Offer 4, provided capacity payments based on the costs of a combustion turbine without upward or downward adjustment of those costs relative to PG&E's projected system reliability during the QF's period of performance. (See D.82-12-120, 10 CPUC 2d 553, 642-43 ordering paragraphs 7, 10.)

PG&E's Table E-2 is constructed under the foregoing principles, but it is completed only through 1987. Thus, those interim Standard Offer 4 QFs (such as the petitioners) with a firm capacity availability date later than 1987 need clarification as to the applicability of those principles to their contracts.[5] Petitioners

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[4] PG&E's interim Standard Offer 4 identifies this schedule as Table E-2, and we will use that label for convenience in the rest of today's decision.

[5] QFs must come on-line within five years of contract signing. (D.83-09-054, mimeo., p. 23.) Because interim Standard Offer 4 was not entirely suspended until April 1985 (see D.85-04-075), QFs signing the interim offer have as late as April 1990 (depending on when the QF signed) to become operational.

(supported by Public Staff) maintain that the principles govern firm capacity payments to all QFs coming on-line consistent with the provisions of their respective interim Standard Offer 4 contracts, and that PG&E could readily extend the payment schedule to encompass 1988, 1989, and 1990 by using the combustion turbine cost escalation factors already implicit in Table E-2. Petitioners also claim that the regulations of the Federal Energy Regulatory Commission (hereafter referred to as FERC rules) expressly give QFs supplying firm capacity the option to receive avoided capacity costs calculated for the term of the contract at the time the contractual obligation is incurred. (18 CFR § 292.304(d)(2).)[6] Interim Standard Offer 4, petitioners argue, bases firm capacity payments on this option, and accordingly Table E-2 must be extended to cover all potential periods of operation under the offer. PG&E maintains in essence that, because Table E-2 presently contains no payment schedule for QFs coming on-line after 1987, the principles do not apply at all to such QFs, and that such QFs should instead receive, by analogy to the Uniform Commercial Code as adopted in California, "a reasonable price at the time of delivery for firm capacity deliveries beginning after 1987." (PG&E, Protest to Petitions for Modification, p. 37.)

B. PG&E's As-Available Capacity Price Schedule[7]

Table D-2 contains forecasted shortage costs for each year from 1983 to 1997. In contrast with the treatment of prices for firm capacity, discussed above, this treatment of as-available capacity prices in interim Standard Offer 4 is a marked departure from the approach taken in any of our other standard offers,[8] and also goes far beyond anything required under the FERC rules.

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[6] The FERC rules implement the federal Public Utility Regulatory Policies Act. That statute and the implementing rules provide a federal framework for state regulation of dealings between utilities and QFs.

[7] This is Table D-2 in PG&E's interim Standard Offer 4, and we will henceforth use this label when referring to this schedule.

[8] Under Standard Offers 1 and 3, which are also contracts for as-available capacity, such capacity is repriced in each general rate case of

Ultrapower is the only petitioner seeking extension of Table D-2. Ultrapower notes that the "fixed price period" in PG&E's interim Standard Offer 4 is so defined as to provide 10 years (from the date of initial energy deliveries) of forecasted as-available capacity prices for a QF with a contract term of 20 years or more. However, unless Table D-2 is extended, interim Standard Offer 4 QFs coming on-line after 1987 could have as little as seven years of price certainty for as-available capacity.

PG&E and Public Staff oppose extension of Table D-2. Public Staff apparently takes the position that "fixed price period" should be construed together with Table D-2 to provide a *maximum* of 10 years of forecasted as-available capacity prices; thus, the fact that some interim Standard Offer 4 QFs would receive less than 10 years of price certainty does not, in Public Staff's view, violate the letter of the contract or the Commission's intent. PG&E argues that "the Commission only approved the 15-year forecast agreed to during the negotiating conference. The number in the adopted forecast cannot rationally be extended beyond 15 years. Negotiation, not methodology tested by evidentiary hearings, generated the numbers." (PG&E, Protest to Petitions for Modification, pp. 19-20.)

C. PG&E's Forecasted Energy Price Schedule[9]

Table B-1 relates to Energy Payment Option 1 and contains energy prices, differentiated by on-peak, partial-peak, and off-peak deliveries, for each year from 1983 to 1997. This table departs radically from the computation of energy prices under any of the other standard offers then extant. Our practice for the short-run offers was and is to price energy as the product of the purchasing utility's incremental fuel cost (updated quarterly) times that utility's incremental energy rate (updated in the general rate case).

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the purchasing utility. At the time we approved interim Standard Offer 4, PG&E had a general rate case every two years.

[9] Identified in PG&E's interim Standard Offer 4, and hereafter in today's decision, as Table B-1.

Ultrapower, again, is the only petitioner seeking extension of Table B-1.[10] Ultrapower again bases its theory in support of extension on its interpretation of "fixed price period" in interim Standard Offer 4. Ultrapower would derive energy prices for the additional years "based on the input assumptions underlying Table B-1 which were applicable at the time Table B-1 was generated. In the alternative, forecasted energy price values for the years 1998 and 1999 may be easily established equal to the 1997 value plus one cent per kilowatt hour each year as an expedient way of providing an energy price term. This is consistent with Southern California Edison Company's resolution of the same issue." (Ultrapower, Petition for Modification, p. 7.)

PG&E and Public Staff oppose extension of Table B-1. Their arguments are quite similar. They note that the energy forecasts in interim Standard Offer 4 were adopted solely as the result of negotiation and without an evidentiary record other than the fact that the forecasts were agreed to. Consequently, according to PG&E and Public Staff, there is no evidentiary basis for extending Table B-1 beyond the years already included. PG&E makes the further point that, although we decided ultimately to make interim Standard Offer 4 available for a longer period than we had originally anticipated, the decision (D.84-08-035) in which we continued the offer's availability does not revise the previously adopted prices or forecasts despite one request for partial revision. Specifically, Independent Energy Producers Association (IEP) had requested that the incremental energy rates used in one of the payment options (Energy Payment Option 3, not at issue in these petitions) be modified based on more recent information. We rejected the request, noting that each payment option is:

> "part of the negotiated package which the Commission approved in D.83-09-054. A change in one term would require the reexamination of all other terms of the standard offer. We prefer to maintain the status quo and adopt modifications to Standard Offer No. 4 following the eviden-

[10] Specifically, Ultrapower seeks extension of the table to include the years 1998 and 1999.

tiary hearings now scheduled in this proceeding. We also note that a QF who finds the terms of interim Standard Offer No. 4 unacceptable may in fact negotiate a separate contract." (D.84-08-035, mimeo., p. 4.)

III. Discussion

A. Table E-2

We think that a fair reading of PG&E's interim Standard Offer 4 makes clear that firm capacity QFs holding contracts under that offer are entitled to levelized payments for such capacity over the term of their contracts. Consequently, Table E-2 must be extended to provide a firm capacity price schedule for all years in which such QFs are entitled to become operational (i.e., within five years of signing the contract). Our examination of D.83-09-054 (approving interim Standard Offer 4) and the FERC rules strongly confirms this reading. Furthermore, we agree with petitioners that the extension is ministerial, given that we specified the appropriate discount rate in D.83-09-054, and the combustion turbine cost escalation factors are already implicit in Table E-2.[11]

The extension of Table E-2 applies to firm capacity QFs whose interim Standard Offer 4 contracts specify an on-line date in 1988, 1989, or 1990. All of the petitioners apparently hold contracts showing on-line dates in 1987 or earlier. QFs such as petitioners who come on-line later than the date specified in their contracts but consistent with the five-year deadline retain their original firm capacity payment schedule but are *not* entitled to escalation. The firm capacity price for these QFs was calculated and fixed when their contractual obligation was incurred, on the

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[11] We note that PG&E itself (in a petition for modification of D.83-12-068) has argued that extension of a firm capacity price schedule for purposes of Standard Offer 2 constitutes a "ministerial act." Not surprisingly, PG&E has asked to withdraw that petition. We have not as yet ruled on the petition or the request, nor do we do so here, as the petition was filed in another proceeding (A.82-12-48).

basis of the operational date they themselves specified in their respective contracts.

PG&E's opposition is predicated chiefly on the theory that to extend Table E-2 would constitute retroactive reformation, contrary to law and to our stated intentions in approving interim Standard Offer 4. But this theory collapses because we are *not* supplying missing terms but rather construing the express terms to give them their clear and logical effect. PG&E's interpretation, on the other hand, contradicts every mention of firm capacity in the relevant documents. Furthermore, PG&E construes an ambiguity (namely, the silence of Table E-2 for the years 1988, 1989, and 1989) so as to cause an essential contract term to fail for indefiniteness. This is contrary to general rules for construing contracts. Finally, PG&E's suggested resolution of the ambiguity is wholly arbitrary: we find not the slightest suggestion, in interim Standard Offer 4 itself or any other relevant source, that the Commission would or could simply make up firm capacity prices as it went along.[12]

PG&E argues that the petitions should be rejected because granting them would increase costs to PG&E, and ultimately ratepayers. This argument (1) ignores the language of interim Standard Offer 4, and (2) requires a crystal ball. The fact is, neither we, nor PG&E, nor QFs know whether the escalation factors in Table E-2 will prove higher or lower than the change in costs of a combustion turbine, or than inflation generally. Furthermore, PG&E has said repeatedly and in many proceedings that it is currently flush with capacity. Logically, then, the firm capacity provided by petitioners and similarly situated QFs will have greater value to PG&E if they come on-line later rather than

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[12] Our failure in D.84-08-035 (continuing the availability of interim Standard Offer 4) to specifically address Table E-2 is not at all surprising, given the identical treatment of firm capacity payments in Standard Offer 2. In fact, for almost a year after we suspended interim Standard Offer 4, new QFs could continue to obtain levelized payments for up to 30 years for firm capacity under Standard Offer 2.

sooner. The escalation factors in Table E-2 do not consider this at all.[13]

B. Tables D-2 and B-1

We reject Ultrapower's request for extension of these tables. Unlike firm capacity pricing, there is no analogue in our other standard offers for the treatment of as-available capacity and energy payments in these tables, and no accepted methodology for extending them.

We regret that our decisions did not address this point specifically; however, both D.83-09-054 and D.84-08-035 contain clear indications that we preferred finalizing our long-run avoided cost methodology to extension of these tables. Our rejection in D.84-08-035 of IEP's request to revise the incremental energy rates was noted earlier. In D.83-09-054 (mimeo., p. 33), we expressed strong reservations concerning the levelized energy payments provided by Option 2 (not at issue in these petitions) of interim Standard Offer 4. To find by implication that the utilities are now *compelled* to extend Tables D-2 and B-1 cannot be justified by reference to interim Standard Offer 4 or the decisions approving that offer.[14]

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[13] PG&E also does not consider the possibility that some of the petitioners and similarly situated QFs may be able to accelerate their development schedules in order to come on-line by the end of 1987 (the last year for which Table E-2 presently shows a price schedule). Such accelerated development would compound the minimum load problems that PG&E claims QFs impose on its system.

[14] Our interpretation of Tables D-2 and B-1 leaves petitioners with at least seven years of price certainty. In contrast, PG&E's interpretation of Table E-2 would leave petitioners with *no* price certainty (as to firm capacity payments).

We emphasize that we do not preclude utilities from completing Tables D-2 and B-1 to provide 10 years of price certainty, based on the data and escalation factors already in the tables.

Findings of Fact

1. The petitions of Ultrapower, GWF, and Thermal for modification of D.83-09-054 and (in Thermal's case) D.82-12-120 request that Table E-2 of PG&E's interim Standard Offer 4 be extended to provide a firm capacity price schedule for QFs coming on-line in the years 1988, 1989, and 1990. The complaint of Basic American Foods in C.86-07-022 requests similar relief.

2. The petition of Ultrapower for modification of D.83-09-054 requests that Tables D-2 and B-1 of PG&E's interim Standard Offer 4 be extended to provide as-available capacity and forecasted energy prices through the year 1999.

3. Interim Standard Offer 4 is the result of a negotiating conference at which the parties agreed on a series of energy and capacity price schedules. The purpose of the schedules is to provide a contract with price certainty equal to or greater than that provided to QFs under Standard Offers 1, 2, and 3.

4. The intent of Table E-2, and other provisions in interim Standard Offer 4 regarding firm capacity QFs, is to establish a payment schedule for firm capacity calculated for the term of the contract at the time the contractual obligation is incurred. This treatment of firm capacity pricing is identical to one of the payment options available to firm capacity QFs under Standard Offer 2.

5. Extension of Table E-2, as requested by petitioners, is essentially ministerial.

6. Tables D-2 and B-1, and other provisions of interim Standard Offer 4, do not guarantee to all QFs signing that offer the same number of years of price certainty regarding as-available capacity and energy payments, irrespective of the year that the QF becomes operational.

7. D.83-09-054 and D.84-08-035 indicate that we did not intend to extend our projections of energy and as-available capacity values before resolution of long-run avoided cost methodological issues.

Conclusions of Law

1. C.86-07-022 should be consolidated with this proceeding for the limited purpose of resolving the firm capacity price issue raised in that complaint. The petition of Dexzel for modification of D.83-09-054 should be dismissed as moot.

2. The request of Public Staff to accept its late-filed response to the petition of Ultrapower should be granted.

3. The request of El Dorado Irrigation District, El Dorado County Water District, and SOFAR Management Authority to withdraw their petition for modification of D.83-09-054 should be granted.

4. Table E-2 of PG&E's interim Standard Offer 4 should be extended to include the years 1988, 1989, and 1990. The extension of Table E-2 should apply to firm capacity QFs whose interim Standard Offer 4 contracts specify an on-line date in 1988, 1989, or 1990. QFs who come on-line later than the date specified in their contracts but consistent with the five-year deadline should retain their original firm capacity payment schedule but are not entitled to escalation.

5. Tables D-2 and B-1 of PG&E's interim Standard Offer 4 should not be extended.

ORDER

1. The petition of Basic American Foods for partial consolidation of Case 86-07-022 with Application 82-04-44 et al. for the purpose of resolving the firm capacity pricing issue is granted. This order resolves that issue.

2. The request of the Public Staff Division to accept its late-filed response to the petition of Ultrapower, Inc. (Ultrapower), for modification of Decision 83-09-054 is granted.

3. The request of El Dorado Irrigation District, El Dorado County Water Agency, and SOFAR Management Authority to withdraw their petition for modification of Decision 83-09-054 is granted.

4. The petitions of Ultrapower, GWF Power Systems Company (GWF), and Thermal Energy Development Corporation (Thermal) for modification of Decision 83-09-054 and (in Thermal's case) Decision 82-12-120 are granted to the extent such petitions seek extension of Table E-2 in interim Standard Offer 4 of Pacific Gas & Electric Company (PG&E) to include the years 1988, 1989, and 1990.

5. Except to the extent granted in ordering paragraph 4, the petitions of Ultrapower, GWF, and Thermal are denied. The petition of Dexzel, Inc., for modification of Decision 83-09-054 is dismissed.

6. Within 20 days of the effective date of this order, PG&E shall file amendments to Table E-2 (firm capacity price schedule) in PG&E's interim Standard Offer 4, consistent with ordering paragraph 4 herein, using a discount rate of 15% (as ordered in Decision 83-09-054) and the combustion turbine cost escalation factors implicit in the table.

7. The amendments to be filed by PG&E in accordance with ordering paragraph 6 constitute a ministerial extension of Table E-2 pursuant to existing provisions of PG&E's interim Standard Offer 4. As such, the amendments shall govern the respective rights and obligations of PG&E and qualifying facilities contracted to sell electricity to PG&E under interim Standard Offer 4 contracts.

8. The extension of Table E-2 applies to firm capacity QFs whose interim Standard Offer 4 contracts specify an on-line date in 1988, 1989, or 1990. QFs who come on-line later than the date specified in their contracts but consistent with the five-year deadline retain their original firm capacity payment schedule.

This order is effective today.

Dated October 16, 1986, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
FREDERICK R. DUDA
STANLEY W. HULETT
Commissioners

I abstain.
STANLEY W. HULETT, Commissioner

APPENDIX G

Decision 86-12-013 December 3, 1986

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application 82-04-44
(Filed April 21, 1982;
amended April 28, 1982,
July 19, 1982, July 11, 1983,
August 2, 1983,
and August 21, 1986)

Application 82-04-46
(Filed April 21, 1982;
amended May 12, 1982,
July 11, 1983, August 10, 1983,
October 27, 1983,
January 4, 1984, May 4, 1984,
June 20, 1984,
and August 20, 1986)

Application 82-04-47
(Filed April 21, 1982;
amended July 11, 1983,
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September 6, 1984,
and August 20, 1986)

Application 82-03-26
(Filed March 8, 1982)

Application 82-03-37
(Filed March 8, 1982)

Application 82-03-62
(Filed March 16, 1982)

Application 82-03-67
(Filed March 18, 1982)

Application 82-03-78
(Filed March 22, 1982)

Application 82-04-21
(Filed April 8, 1982)

Case 86-07-022
(Filed July 7, 1986)

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2. And Related Matters.

ORDER MODIFYING DECISION 86-10-038

I. Introduction

By Decision (D.) 86-10-038, we interpreted certain payment provisions in interim Standard Offer 4 contracts between qualifying facilities (QFs) and Pacific Gas and Electric Company (PG&E). The decision responded to several petitions for modification of D.83-09-054 and also to a complaint (Case 86-07-022) that in part concerned the same issue of interpretation. Various parties have applied for rehearing of D.86-10-038.[1] The issues presented in the rehearing applications boil down to two: (1) which date (the "scheduled operation date" or the "firm capacity availability date") determines the firm capacity price; and (2) what should be done about prices in years that appear to come within the "fixed price period" of a given QF but that presently do not have prices indicated in the relevant payment schedules in PG&E's interim Standard Offer 4.

We address only the first issue in today's decision because, unfortunately, D.86-10-038 creates a serious ambiguity in this regard and should be clarified immediately. The second issue will be the subject of a later decision.

[1] The applicants for rehearing are: PG&E, Independent Energy Producers Association (IEP); Foster Wheeler Power Systems, Inc. (Foster); Ultrapower, Inc. (Ultrapower); and Basic American Foods (Basic).

II. Firm Capacity Availability Date

When in D.86-10-038 we analyzed the question of extending Table E-2, which is the firm capacity price schedule in PG&E's interim Standard Offer 4, we referred several times to the QFs "on-line" or "operational" date. (See D.86-10-038, mimeo., p. 11.) Unfortunately, PG&E's interim Standard Offer 4 contract form refers both to a "*scheduled operation date*" (see Article 3(c)), which is the day that (in the QF's estimation) the facility will first produce energy for delivery to PG&E, and to a *firm capacity availability date*" (see Article 5), which may be some time after the QF's first energy deliveries. The QF specifies its estimate of the date of scheduled operation when signing the contract; the date of firm capacity availability is *not* specified, but it is the latter date that dictates the firm capacity price in Table E-2. The use of the two different dates in the contract requires clarification of our use of the terms "on-line" and "operational" date.

We have concluded, in light of the specification of "firm capacity availability date" in Table E-2, that we cannot require the firm capacity price to be determined from the date of initial energy delivery. Regardless of the date that the QF scheduled for initial energy delivery at time of contract signing, so long as the QF is otherwise in compliance with its contract, the QF is entitled to have its firm capacity price determined in accordance with Table E-2, based on the date that the QF delivers firm capacity to the utility. (See definition of "*firm capacity availability date*" in Appendix A of PG&E's interim Standard Offer 4.)[2]

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[2] We will not, however, require PG&E to extend Table E-2 beyond 1990. We fully suspended the availability of interim Standard Offer 4 in April 1985; thus, consistent with the requirement that the QF must begin power deliveries within five years of contract signing (see Article 10), all interim Standard Offer 4 QFs will have had to begin power deliveries by April 1990. We think it is reasonable in this context to expect that most QFs in such a situation could achieve firm capacity within eight months, i.e., by the end of 1990. (We note that Basic, at page 7 of its application for rehearing, asserts that the "shakedown and testing period," starting from initial turbine roll, "is typically between 45 and 90 days in duration.") In any event, such QFs are not inherently

Finding of Fact

The use of the terms "scheduled operation date" and "firm capacity availability date" in PG&E's interim Standard Offer 4 makes ambiguous our analysis in D.86-10-038 of the firm capacity price schedule in that offer.

Conclusion of Law

The QF under PG&E's interim Standard Offer 4 is entitled to have its firm capacity price determined in accordance with Table E-2, based on the date that the QF makes firm capacity available to the utility.

Therefore, IT IS ORDERED that Decision 86-10-038 is modified as follows:

1. The first full paragraph of page 11 (at lines 7-17 of that page) is deleted.

2. The second and third sentences of Conclusion of Law 4 are deleted.

3. Ordering Paragraph 8 is deleted.

This order is effective today.

Dated December 3, 1986, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
FREDERICK R. DUDA
STANLEY W. HULETT
Commissioners

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entitled to an indefinite capacity price extension, especially when the offer's availability had been suspended more than five years previously.

APPENDIX H

Decision 86 12 104 December 22 1986

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application 82-04-044
(Filed April 21, 1982;
amended April 28, 1982,
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Application 82-04-046
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October 27, 1983, January 4, 1984,
May 4, 1984, June 20, 1984,
and August 20, 1986)

Application 82-04-047
(Filed April 21, 1982;
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August 2, 1983, September 6, 1984,
and August 20, 1986)

Application 82-03-26
(Filed March 8, 1982)

Application 82-03-37
(Filed March 16, 1982)

Application 82-03-62
(Filed March 16, 1982)

Application 82-03-67
(Filed March 18, 1982)

Application 82-03-78
(Filed March 22, 1982)

Application 82-04-21
(Filed April 8, 1982)

Case 86-07-022
(Filed July 7, 1986)

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2. And Related Matters

ORDER DENYING REHEARING AND MODIFYING DECISION 86-10-038

PACIFIC GAS AND ELECTRIC COMPANY (PG&E), BASIC AMERICAN FOODS, INC. (Basic), FOSTER WHEELER POWER SYSTEMS, INC. (Foster), INDEPENDENT ENERGY PRODUCERS' ASSOCIATION (IEP), AND ULTRAPOWER, INC. (Ultrapower) have filed applications for rehearing of Decision (D.)86-10-038. We have considered all allegations of error raised in those applications and are of the opinion that the applications of Basic, Foster, and Ultrapower are moot and that sufficient reason for granting rehearing has not been shown in the applications of PG&E and IEP.

However, we find that the allegation of IEP with respect to the extension of Table B-1, which establishes energy prices through 1997, is well taken. The intent of the parties in placing Table B-1 into interim Standard Offer 4 (interim SO4) was to provide energy price certainty for up to ten years for each QF signing under that contract. Without the requested extension, those QFs coming online after 1987 do not have such price certainty. The same is true for Table D-2, which represents as-available capacity prices. We will accordingly extend these Tables to cover the years 1998-2000.

We will not, however, carry forward the price escalation of those tables into the three extended years, as we did with Table E-2 values in D.86-10-038. That table is merely an expression of the values of the agreed-upon price proxy, the cost of a combustion turbine (CT), carried over all applicable years. The change due to escalation was thereby made merely ministerial. Tables B-1 and D-2, on the other hand, are based on negotiations between the parties, which cannot be replaced without long and complex hearings for the sole purpose of adopting a workable methodology. Such hearings for the purpose of determining the increment or

decrement for three years' worth of pricing would be of far more cost than benefit to all concerned.

We are aware that in some instances utilities and QFs have agreed on escalated prices for missing years under the schedules discussed above. Our action today is not intended to vacate such agreements or to critique their reasonableness. As stated above, we have consistently encouraged utilities and QFs to reach accommodation short of litigating disputes before us or other tribunals. There may well be other difficult questions of interpretation lingering in the standard offers. We think it clear that everyone's efforts are best put to use in this proceeding on refinements to resource planning, capacity valuation, and updating for *prospective* application to QF/utility transactions. It is not the business of this Commission or the utilities to adjust for current perceptions of oversupply by harsh dealing toward QFs already under contract.

The simplest method of completing the ten years of price certainty in these tables is to carry the last value, that of 1997, forward over the next three years. This method at least provides price certainty and sets the price at the last negotiated price level; if the price is too high or too low, then the harm suffered by either the utility or the QFs will thus be minimized. Therefore,

IT IS ORDERED that,

1. The applications for rehearing are hereby denied.

2. PG&E is hereby ordered to file amendments to Tables B-1 and D-2 to interim Standard Offer 4, extending the 1997 prices of both tables into the years 1998, 1999 and 2000. This filing shall take place within 30 days of the effective date of this order.

3. Decision 86-10-038 is modified as follows:

a. Section III.B is deleted (*mimeo.*, pp. 12-13).

b. The sixth line from the bottom of *mimeo.* p.10 is deleted, so that Section III.A becomes Section III.

c. Finding of Fact 6 is modified to read:

"Tables D-2 and B-1, and other provisions of interim Standard Offer 4, do not guarantee to all QFs signing that offer

the same number of years of price escalation regarding as-available capacity and energy payments, irrespective of the year that the QF becomes operational, but they do guarantee a minimum of up to ten years of price certainty."

d. Conclusion of Law 5 is modified to read:

"Tables D-2 and B-1 of PG&E's interim Standard Offer 4 should be extended through the year 2000, but not escalated beyond the prices forecast for 1997."

This order is effective today.

Dated December 22, 1986, at San Francisco, California.

DONALD VIAL
President
VICTOR CALVO
FREDERICK R. DUDA
STANLEY W. HULETT
Commissioners

Commissioner G. Mitchell Wilk
present but not participating.

APPENDIX I

DEC. NO. 86-12-104 Mailed 12/26/86

Copy of: ORDER DENYING REHEARING AND MODIFYING DECISON 86-10-038 mailed to the following:

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APPENDIX J

Before the Public Utilities Commission
of the State of California

Consolidated Application No. 82-04-044 and
Application No. 82-03-026
Second Application of PACIFIC GAS AND ELECTRIC COMPANY
for approval of Certain Standard Offers
Pursuant to Decision No. 82-01-103
in Order Instituting Rulemaking No. 2
(U-39E)

Application for Rehearing
of Decision 86-10-038
by Pacific Gas and Electric Company

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I
INTRODUCTION

In accordance with California Utilities Code § 1731 and Rule 85 of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company ("PGandE") requests rehearing of those portions of Decision 86-10-038 (the "Decision") issued October 16, 1986 which pertain to the firm capacity price payable under interim Standard Offer No. 4 power purchase agreements to sellers that establish firm capacity availability dates after 1987.

The Decision gives sellers who initially promised to begin operations by the end of 1987 the right to retain the corresponding prices set forth in the contract even in the event they delay the start of operations past 1987. It further gives sellers who initially promised to begin operations after 1987 new firm capacity prices even higher than those set forth in their power purchase agreements. The additional cost to PGandE ratepayers will be substantial. In ordering changes to the fixed firm capacity prices, the Decision works changes in executed interim SO4 agreements that cannot be countenanced under ordinary rules of contract interpretation, that counter the Commission's own prohibition against retroactive modification to interim SO4 agreements and that violate the Public Utility Regulatory Policies Act of 1978 ("PURPA").

II
BACKGROUND

Decision 86-10-038 responded to Petitions for Modification of Decisions 83-09-054 and 82-12-120 by Thermal Energy Development Corporation, GWF Power Systems, Inc. and Ultrapower, Inc. The complaint of Basic American Foods, Inc. (C.86-07-022) was consolidated with these petitions for the purpose of resolving the firm capacity price schedule. (Collectively, "petitioners"). In the interim SO4 contracts for each of their seventeen projects, petitioners stated that the scheduled operation date was 1987 or earlier.

Petitioners each requested that new, higher prices for firm capacity deliveries beginning after 1987 be added to their executed interim SO4 power purchase agreements. The last price in Table E-2 of interim SO4 specifies a levelized price of $160/kw-year for thirty years of firm capacity deliveries beginning in 1987. Article 12 of interim SO4 states that the contract terminates unless energy deliveries begin within five years of contract execution.

Petitioners argued Article 12 implicitly entitled them to new firm capacity prices based on an escalation of the existing interim SO4 contract prices if they begin firm capacity deliveries after 1987 but within the five-year deadline. Ultrapower also argued that the fixed forecasted energy (Table B-1) and as-delivered capacity (Table D-2) price schedules should be similarly extended so that sellers beginning deliveries of energy and as-delivered capacity within the five-year period could receive ten years of fixed prices.

Decision 86-10-038 rejected Ultrapower's request to extend the energy and as-delivered capacity price schedules. The Commission concluded that neither interim SO4 or its decisions regarding interim SO4 justified the extension of those schedules by implication. However, the Commission reached the opposite conclusion with respect to the firm capacity price schedule. The Decision orders PGandE to add new firm capacity prices for years 1988 to 1990 to Table E-2. The Decision makes these new prices available only to sellers which initially specified operation dates after

1987 in their interim SO4 contracts. It allows sellers such as petitioners which specified operation dates prior to the end of 1987 to retain the original Table E-2 prices even though they begin firm capacity deliveries after 1987. But such sellers are not eligible to receive the new prices.

PGandE concurs in the Commission's decision that extension of the energy and as-delivered price schedules cannot be justified. But the same reasoning which made extension of Table B-1 and Table D-2 unjustifiable applies also to Table E-2. The Decision's extension of Table E-2's availability and addition of new escalated prices is contrary to the express language of interim SO4. It cannot be sustained as mere contract interpretation. It accordingly violates both the Commission's own prohibition against retroactive changes to executed interim SO4 agreements and PURPA.

III
DISCUSSION

A. The Express Terms Of Interim SO4 Preclude Implication Of New Fixed Firm Capacity Prices Derived From An Escalation Of Table E-2

The keystone of the Decision's extension and escalation of the firm capacity price schedule is that it is "*not* supplying missing terms but rather construing the express terms to give them their clear and logical effect." Mimeo p. 11 (Emphasis in original). Interim SO4 as approved by the Commission in Decision 83-09-054 and extended in Decision 84-08-035 undeniably does not contain any prices for firm capacity deliveries after 1987. The express language of interim SO4 precludes the implication of any new prices. Accordingly, the Decision's order that PGandE extend the availability of Table E-2 and add new escalated prices cannot be sustained.

1. Rules Of Contract Interpretation Do Not Permit Implication Of New Escalated Prices

The Decision states that interim SO4 entitles firm capacity sellers to levelized firm capacity prices throughout the contract

term./Mimeo, p. 10./Interim SO4 makes no such promise. Article 5 states only that payment shall be "determined in accordance with Appendix E." Appendix E, Section E-1 refers only to the "*firm capacity prices* in Table E-2." (Underscoring in original.) Section A-2 defines "firm capacity price" only in reference to Table E-2. It is:

> the price for *firm capacity* applicable for the *firm capacity availability date* and the number of years of *firm capacity* delivery from the *firm capacity price schedule,* Table E-2, Appendix E.

Accordingly, interim SO4 nowhere expressly promises the seller that it will receive fixed levelized firm capacity prices throughout its term of agreement no matter when it begins firm capacity deliveries. To the contrary, interim SO4 repeatedly and consistently states that the firm capacity prices are those contained in Table E-2. Those prices end after 1987. Thus, interim SO4 only promised fixed levelized firm capacity prices to sellers that begin firm capacity deliveries by the end of 1987.

The Decision can only be sustained if the extension of Table E-2's availability and new prices it ordered be added to executed interim SO4 contracts are already part of those agreements by implication. But interim SO4 cannot be so construed. The Commission has stated that the standard offers are to be "a contract in the 'traditional' legal sense." Decision 85-06-163, Mimeo, p.29 (June 21, 1985). Ordinary rules of contract interpretation therefore apply.

Implied terms are not favored. *Cousins Investment Co. v. Hastings Clothing Co.,* 45 Cal. App. 2d 141, 143 (1941). Terms in an agreement may be implied only if each of the following conditions are met:

> (1) the implication must arise from the language used or it must be indispensable to effectuate the intention of the parties; (2) it must appear from the language used that it was so clearly within the contemplation of the parties that they deemed it unnecessary to express it; (3) implied covenants can only be justified on the grounds of legal necessity; (4) a promise can be implied only where it can be rightfully

> assumed that it would have been made if attention had been called to it; and (5) there can be no implied covenant where the subject is completely covered by the contract.

Hinckley v. Bechtel Corp., 41 Cal. App. 3d 206, 211 (1974). An implied term cannot rest solely on the facts surrounding the execution of a contract. "It must have a basis in the contract itself." *Stockton Dry Goods Co. v. Girsh*, 36 Cal. 2d 677, 680-681 (1950). "Legal necessity" is the single most important factor. *Hinckley, supra*, 41 Cal. App. 3d at 212. The language of interim SO4 does not permit the implication of new escalated fixed prices for firm capacity deliveries beginning after 1987. Nor is the implication of such prices necessary to salvage the agreement. Accordingly, under the rules cited above, no such prices can be implied.

The express language of interim SO4 precludes the implication of fixed escalated prices after 1987. Article 12 is the only express term in interim SO4 on which the Decision relies for in its conclusion that Table E-2 should be extended. Article 12 specifies the term of agreement. For firm capacity sellers, it provides that:

> This Agreement shall be binding upon execution and shall remain in effect for ____ years from the *firm capacity availability date*; provided, however, that it shall terminate if energy deliveries do not start within five years of the execution date.

The only conceivable basis in interim SO4 for implying extended and escalated prices is the difference between the Article 12 and Table E-2 timetables. But the difference does not allow implication of fixed, escalated post-1987 prices under the rules cited above.

First, Article 12 and Table E-2 are not inconsistent. The difference in their timetables does not create any ambiguity. The two provisions are entirely independent. Interim SO4 does allow a seller to delay operation for up to five years before the agreement automatically terminates. But interim SO4 does not guarantee that the seller will receive the same firm capacity price that it would have received but for the delay, let alone a price that is even higher than those specified in Table E-2. The Decision

attempts to make the Article 12 and Table E-2 timetables run concurrently. But the express terms of those provisions separate the two timetables.

If a seller wishes to avoid termination under Article 12, it must begin "energy deliveries" within five years. But if a seller wishes to secure a fixed levelized firm capacity price under Table E-2, it must establish a "firm capacity availability date" by the end of 1987. That date is much different than the date on which energy deliveries begin. It is:

> The day following the day during which all features and equipment of the *Facility* are demonstrated to PGandE's satisfaction to be capable of operating simultaneously to deliver *firm capacity* continuously into PGandE's system as provided in this Agreement.
>
> Interim SO4, Section A-1.

Consequently, even under the Decision, a seller can begin energy deliveries within the five-year deadline, but still not establish a firm capacity availability date until much later. The logic of the Decision's effort to force identity between the five-year timetable and the Table E-2 timetable would thus lead to the absurdity that the firm capacity prices should be extended not merely to meet the five-year deadline, but indefinitely.

The independence between the Article 12 five-year deadline and the Table E-2 prices has been apparent from the inception of interim SO4. Interim SO4 was authorized for use in Decision 83-09-054 issued on September 7, 1983. The Article 12 five-year deadline could occur no sooner than 1988. Yet the Table E-2 prices expire at the end of 1987.

This obvious lack of correspondence shows the timetables were intended to be different, not that the prices should be implicitly extended. The five-year deadline in Article 12 sets an outside limit on development of a project. It accordingly assists in generation and transmission resource planning. Interim SO4 otherwise provides no direct control on when a project must begin operations. Article 12 also serves to reduce speculation and eliminate stale contracts. But Article 12 does not contain any

reference to prices. It contains no guarantee that a seller beginning operations after 1987 will retain the Table E-2 prices, let alone secure higher prices. Since neither the language of Article 12 nor its purpose require consistency with Table E-2, it cannot be interpreted to imply extended or escalated firm capacity prices.[1]

Moreover, even if it were possible to construe the five-year provision to govern Table E-2, the Decision further declares not only that the time period during which the Table E-2 prices are available is impliedly extended, but that the prices themselves must be impliedly escalated. Article 2 precludes any interpretation of interim SO4 which would imply the addition of new prices based on an escalation of Table E-2 in executed interim SO4 agreements.

Article 2 of interim SO4, which the Decision ignores, explicitly prohibits exactly the type of price change which the Decision orders. Article 2 was approved in Decision 83-09-054 as part of PGandE's proposed interim SO4. It states that "*the Parties expressly commit to the prices fixed in this Agreement for the applicable period of performance* and shall not seek to or have a right to renegotiate such prices *for any reason.*" Further, "*Seller waives any and all rights to judicial or other relief from its . . . prices set forth in Appendices . . . E. . . .*" (Emphasis added.) Article 2 alone negates any construction of interim SO4 which would change the fixed firm capacity prices on the basis of implication.

The explicit language of Article 2 prevails over any contrary meaning Article 12 might otherwise imply. "It is clear that implication that would otherwise be reasonable should not be made when the contrary is indicated in clear and express words." *Clutts v. Southern Methodist Univ.*, 626 S.W. 2d 334, 336 (Tex. App. 1982), quoting Corbin, 3A *Corbin on Contracts* § 564 at 298 (1960). "No implied condition can be inserted as against the

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[1] Even if an inconsistency existed between Article 12 and Table E-2, the more specific provisions of Table E-2 would control the general Article 12 five-year provision. *See* Cal. Civ. Proc. § 1859. *Accord McNeely v. Claremont Management Co.*, 210 Cal.App.2d 749 (1962).

express terms of the contract." *Cousins Investment Co. v. Hastings Clothing Co.*, 45 Cal.App.2d 141, 148 (1941). The express Article 2 prohibition against any changes to the fixed contract prices makes untenable the Decision's implication of new escalated firm capacity prices.

2. Open Price Terms May Be Filled By A "Reasonable" Market Price

Because Table E-2 only provide fixed prices for firm capacity availability dates through 1987, a seller's delay in proving firm capacity past 1987 creates open price term for firm capacity payments. This result does not "cause an essential contract term to fail for indefiniteness," as the Decision states. Construing Table E-2 to provide fixed capacity prices only to sellers who begin firm capacity deliveries by the end of 1987, and "reasonable" market prices to sellers who delay past 1987, is the only interpretation that reconciles the firm capacity pricing terms with Article 2 and Article 12.

Payment of market prices to sellers who establish firm capacity availability dates after 1987 is not "wholly arbitrary," as the Decision states. Nor does it mean "making up" firm capacity prices. Construing a contract to provide payment of "reasonable" market prices when the parties failed to specify a price in a contract but intended to make an agreement is hornbook contract law. In such cases, a reasonable market price is the price due as a matter of law.

The California Uniform Commercial Code states that if a contract says nothing about price but the parties intended to make an agreement, "the price is a reasonable price at the time of delivery." Cal. Comm. Code § 2305(1). This provision is a specific application of the more general rule that "reasonable terms are implied by law to fill contract gaps. The Restatement (Second) of Contracts § 204 states:

> When the parties to a bargain sufficiently defined to be a contract have not agreed with respect to a term which is essential to a determination of their rights and duties, a term which is reasonable in the circumstances is supplied by the court.

The absence of specific intent by the parties that the "reasonable" term added by law be part of their contract is irrelevant. The "gap-filler provisions" of the UCC "have substantive effects. In other words, the contract . . . was made subject to this subdivision of the code and its requirements . . . were thereby added to the obligations of the parties under the contract." *Shea-Kaiser-Lockheed-Healy v. Department of Water & Power,* 73 Cal.App.3d 679, 689 (1977).

B. FERC Regulations And The Commission's Prior Decisions Do Not Support Implication Of New Fixed Firm Capacity Prices

1. The Commission's Earlier Decisions Do Not Justify Changes In Table E-2

As the Decision notes, interim SO4 was developed in 1983 through negotiations between the utilities, QF representatives and Commission staff. As it also notes, interim SO4 represents to some extent a cut-and-paste of then-existing standard offers. In particular, Table E-2 was adopted intact from the 1983 version of Standard Offer No. 2 ("SO2"). But the conclusion to be reached from interim SO4's origins is the opposite of that in the Decision, namely that Table E-2 should be extended by implication. Rather it shows that such an interpretation cannot be sustained.

PGandE incorporated the firm capacity prices that had been agreed to during the negotiating conference into proposed interim SO4, and presented the entire standard offer to the Commission for approval. The proposed interim SO4 presented in PGandE's application only contained fixed firm capacity prices for the years 1982 through 1987. Interim SO4 did not receive the benefit of any evidentiary hearings. The Commission did not have any record before it that would have allowed it to approve anything other than what the negotiators presented to it. *See* D.83-09-054, mimeo at pp.8, 11; D.85-04-075, mimeo at p.19.

The Commission's approval of interim SO4 was accordingly specifically limited to the contents of PGandE's application. Ordering paragraph 1 provides:

1. *Standard Offer #4, Payment Options #1 through #3, as proposed by the Pacific Gas and Electric Company* (PG&E), San Diego Gas and Electric Company (SDG&E), and Southern California Edison Company (Edison), *shall be used by those utilities until further order* of this Commission, but, in any event, for a minimum of six months and for a maximum of two years after the effective date of this order. *Id.* (Emphasis added.)

Thus, Decision 83-09-054 approved nothing beyond the set of prices presented in PGandE's application. Those prices are identical to the prices contained in Table E-2 interim SO4. Both Decision 83-09-054 and PGandE's Third Amendment to A.82-04-044 (July 11, 1983) accurately state that the firm capacity prices provided in interim SO4 are levelized over the term of agreement. But neither even suggests that the interim SO4 price schedule would be available for a longer time or provide higher prices than the Table E-2 proposed by PGandE and approved by the Commission.

The Decision's reliance on Standard Offer No. 2 to justify extension of Table E-2 is misplaced. The SO2 firm capacity price schedule has been updated and extended, but only for prospective application to new contracts. The revisions have never applied to executed SO2 contracts. New escalated prices have never been implied for the period between the end of the SO2 fixed price schedule and its five-year deadline. Yet the Decision mandates such revisions in executed interim SO4 contracts. However, revisions to executed interim SO4 contracts are even more insupportable than changes to executed SO2 contracts. As Decision 84-08-035, mimeo, p.4 notes, interim SO4 was a "negotiated package." "A change in one term would require the reexamination of all other terms in the Standard Offer." Extension of Table E-2 without securing offsetting ratepayer benefits for the overpayments which are certain at least through the intial contract term tips interim SO4's economic balance entirely in the seller's favor.

2. The FERC Regulations Do Not Require Extension Of Table E-2

The FERC regulations do not compel the conclusion that Table E-2 must by implication be extended. Section 292.304(d)(2) states only that a QF have the option prior to the beginning of the "specified term" to receive payment based on either:

> (i) the avoided costs calculated at the time of delivery; or
> (ii) the avoided costs calculated at the time the obligation is incurred.
>
> 18 C.F.R. § 292.304(d)(2) (1986).

Table E-2 provides prices based on avoided costs calculated at the time the obligation was incurred for firm capacity availability dates through 1987. Whether a seller establishes a firm capacity availability date by the end of 1987 is entirely within the seller's control. A seller's inability to begin firm capacity deliveries in time to obtain the Table E-2 fixed prices results from the seller's delay, not from any deficiency in its agreement.

Under Article 12, the term of agreement for firm capacity sellers does not begin until the "firm capacity availability date." Interim SO4 therefore gives a seller the choice before the "specified term" begins of securing a fixed price under Table E-2 or delaying firm capacity deliveries past 1987 and receiving avoided cost calculated at the time of delivery. The absence of fixed firm capacity prices after 1987 in interim SO4 is fully consistent with the FERC regulations.

Indeed, implying an extension of the Table E-2 prices after 1987 would eliminate the seller's option to select a price calculated at the time of delivery. If the value of capacity had risen, not fallen, under the Decision's interpretation of Table E-2, the sellers could not have benefited.[2] Thus, far from compelling extension of

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[2] The possibility that capacity values would rise above the Table E-2 price was not as far fetched in 1983 as it may now seem. The firm capacity price schedule adopted in D.83-12-068, Table VI-4, mimeo at

Table E-2, the FERC regulations rule out any extension or escalation of the fixed firm capacity prices.

C. The Addition Of New, Escalated Fixed Prices To Executed Interim SO4 Contracts Exceeds The Commission's Authority And Violates PURPA

1. The Commission's Earlier Orders Prohibit The Addition Of New Prices To Executed SO4 Contracts

This Commission has repeatedly emphasized that no retroactive changes would or could be made to executed SO4 contracts. Decision 83-09-054 (Sept. 7, 1983) makes clear that a QF that selects interim SO4 is to be bound by its initial decision:

> Those who contract under interim Standard Offer #4 will not be subject to having terms or *prices* changed later, except as narrowly and specifically ordered by this decision. *Any changes* made to this standard offer in the future *will only apply to those contracting after such changes.*
>
> *Id.* at p.3 (Emphasis added.)

In rejecting a utility-proposed "regulatory authority" clause, the Commission stated that "[i]n ordering the clauses removed we recognize that we cannot order retroactive changes to interim Standard Offer #4 contracts but, given the restrictions placed on the use and availability of this negotiated standard offer, we are willing to commit to that loss in flexibility." (*Id.* at pp.39-40.) Thus, the Commission has barred even itself from making retroactive changes in interim SO4.

Accordingly, no matter what the Commission's continuing regulatory authority over interim SO4 might otherwise be, it legally disabled itself from exercising such authority with respect to interim SO4 on a retroactive basis. *See also* D.85-06-163, p.28 (June 21, 1985). As a consequence, the Commission lacks the authority to extend the availability of Table E-2 or add new escalated firm capacity prices to executed SO4 contracts. Ordering PGandE to amend its executed SO4 contracts to extend Table

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349 (Dec. 22, 1983) for use in SO2 contains even higher prices than Table E-2.

E-2 and to add new, escalated fixed prices was therefore legal error.

2. The Addition of New, Escalated Fixed Prices Violates PURPA

Section 210(b) of PURPA, 16 U.S.C. § 824a-3(b), decrees that the rate an electric utility pays for QF power shall not exceed the utility's avoided cost. Absent a waiver from FERC or, arguably, a state statute specifically authorizing payments in excess of avoided cost, avoided cost is the maximum rate the Commission may set.[3] The Commission has not obtained a waiver from FERC nor does there exist any California statute directing utilities to purchase QF power at prices in excess of avoided cost. In ordering PGandE to pay new firm capacity prices that the Commission has never determined to reflect avoided cost, the Decision violates PURPA.

As discussed earlier, the FERC rules require that avoided cost be calculated as of the time of delivery or as of the time of contract execution. 18 C.F.R. § 292.304(D) (1986). Ordering Paragraph 6 of the Decision orders PGandE to file amendments to Table E-2 to add new prices for years 1988, 1989 and 1990 using a discount rate of 15% and "combustion turbine cost escalation factors implicit in the table." The resulting figures for a thirty-year contract are $172/kw-year for 1988, $184/kw-year for 1989 and $196/kw-year for 1990. These prices do not represent avoided cost calculated as of the time of delivery. Indeed, they are dramatically in excess of current calculations of avoided cost. No Commission decision ever determined that the new escalated

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[3] *Compare Kansas City Power & Light Co. v. State Corp. Com'n,* 234 Kan. 1052, 676 P.2d 764, 765 (1984) (State Corporate Commission had no jurisdiction to order utility to purchase QF power at rate in excess of the utility's avoided cost) *with Consolidated Edison v. Public Serv. Comm'n,* 472 N.E. 2d 981, 63 N.Y.2d 424 (1984), *appeal dismissed, Consolidated Edison Co. v. Pub. Serv. Comm'n,* 105 S.Ct. 1831, 85 L.Ed.2d 132 (1985). (State statute specifically authorizing an above avoided-cost payment of 6 cents per kilowatt hour for QF energy, gave the Public Service Commission authority to order payments in excess of avoided cost).

prices the Decision ordered be added to interim SO4 contracts represented avoided cost. Accordingly, those prices violate PURPA.

Decision 82-12-120 required PGandE to use certain assumptions in calculating firm capacity prices. PGandE's 1983 SO2 contained the resulting prices. Those prices, which are identical to Table E-2, alone represent avoided cost "calculated at the time the obligation is incurred." The assumptions used to produce those numbers are not "avoided cost." The assumptions and methodology used to produce the Table E-2 prices were intended to be valid for only a limited period of time. *See* Decision 83-10-093, mimeo, p.12 (Oct. 19, 1983); Decision 84-03-092, mimeo, p.19 (March 21, 1984). In fact, they were superseded only four months later in PGandE's 1984 Test Year Rate Case, which approved new firm capacity prices. *See* Decision 83-12-068, Table VI-4, mimeo, p.349 (Dec. 22, 1983).

Calculating new firm capacity prices based on the outdated assumptions used to produce the Table E-2 numbers does not produce prices that meet either of the FERC rule's two-prong test. The resulting prices do not represent avoided cost calculated at the time sellers executed interim SO4 contracts and they certainly do not represent avoided cost calculated at the time of delivery. The Response of Independent Energy Producers Association (IEP) to Petitions For Modification Of Decision No. 83-09-054 Regarding Extension Of Firm Capacity Tables (dated Oct. 6, 1986) shows calculation of the new escalated firm capacity prices is not "ministerial." Instead, calculation of the new escalated firm capacity prices as ordered by the Decision requires making new assumption that were never approved by the Commission in any of its earlier decisions including Decision 82-12-120. IEP dismisses these new assumptions as trivial. Nonetheless, the need to make new asumptions in calculating the new escalated prices for years 1988-1990 establishes that in ordering PGandE to pay such prices, the Decision violates the FERC regulations and PURPA.

D. The Decision Substantially Increases The Cost Of QF Power To PGandE Customers And Gives A Windfall To "Gold-rush" QFs

It does not require a crystal ball to determine that the Decision will substantially increase the cost of QF power to PGandE and its customers. It is precisely because PGandE is, as the Decision notes, flush with capacity that the overpayment is virtually certain. PGandE's submittals in the OIR-2, Phase II compliance filing show PGandE has virtually no need for new capacity until the mid-1990's at the earliest. Overpayment during the early years is thus certain. *See also* Decision 86-10-044, mimeo, p.11 (Oct. 16, 1986). Only in the unlikely event that capacity values after 2000 substantially exceed both the 1982 forecast on which the capacity values in Table E-2 is based as well as current estimates will the early and certain overpayments be recouped.

The additional payments that the Decision mandates are substantial. PGandE previously calculated that if petitioners were paid the new escalated firm capacity prices for deliveries beginning in 1988 instead of PGandE's current estimate of avoided cost, the additional payments for petitioners' seventeen project would be almost $1.5 billion over the contract term ($401 million net present value), or about $56 million annually.[4] In limiting the price to that corresponding to petitioners' scheduled operation date, the Decision reduces the additional payments, but by less than 10 percent.

At least twelve projects representing about 418 MW of firm capacity which either have allocations under the interim solution or are located outside a transmission-constrained area specified scheduled operation dates after 1987 in their interim SO4 contracts. The difference between paying these sellers the escalated

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[4] *See* PGandE's Protest to Petitions for Modification and/or Clarification of Decisions 83-09-054 and 82-12-120 by Ultra Power, Inc., Thermal Energy Development Corp. and GWF Power Systems Co. dated September 12, 1986, Exhibit 2, p.1; and PGandE's Errata to Reply to Basic American Food's Petition for Consolidation and Expeditious Resolution of the Firm Capacity Issue into OIR2 Proceedings and Motion to Dismiss dated October 15, 1986.

prices ordered by the Decision and PGandE's current estimate of avoided cost is more than $1.2 billion over the contract terms ($335 million net present value) or more than $20 million annually. The value to PGandE of having QFs begin operation in 1990 instead of earlier is much less than the difference between the Table E-2 prices and the escalated prices, and nowhere near $1.2 billion.

Petitioners executed each of their seventeen interim SO4 contracts following the Commission's October 17, 1984 order suspending interim SO4 energy payment option 3 for QFs over 50 megawatts. Of the seventeen interim SO4 contracts, ten were executed by petitioners in April, 1985. All but one of the twelve projects with scheduled operation dates after 1987 have interim SO4 contracts executed after October 17, 1984; the exception was executed on October 15, 1984. Seven of the twelve were executed in April, 1985. Sellers apparently disregarded the immaturity of their project in their haste to obtain the favorable prices of an offer that many believed would soon be withdrawn. Sellers' haste should not entitle them to even higher fixed prices for even longer periods than their interim SO4 contracts now provide. Yet this result the Decision mandates.

IV
CONCLUSION

PGandE urges the Commission to grant rehearing of the Decision's extension of Table E-2 and addition of new escalated firm capacity prices for sellers who fail to begin firm capacity deliveries by the end of 1987. Article 2 and ordinary rules of contract intepretation bar implication of extended and escalated prices. The Decision's changes to prices in executed interim SO4 contracts exceed the Commission's authority and violate PURPA. It also substantially increases the high cost of power purchased under interim SO4 contracts. For these reasons, PGandE asks that rehearing of the Decision be granted and that sellers be held to the prices expressly provided in their interim SO4 contracts.

Respecfully submitted,

HOWARD V. GOLUB
LINDA L. AGERTER

By LINDA AGERTER
Linda Agerter
Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: November 17, 1986

APPENDIX K

Pacific Gas and Electric Company

Standard Offer #4
Power Purchase Agreement
for
Long-Term Energy
and Capacity

from

Qualifying Cogeneration
and
Small Power Production Facilities

September 1983

Long-Term Energy and Capacity
Power Purchase Agreement
Between

_____

and
Pacific Gas and Electric Company

_____ ("Seller"), and PACIFIC GAS AND ELECTRIC COMPANY ("PGandE"), referred to collectively as "Parties" and individually as "Party", agree as follows:

Article 1 Qualifying Status

Seller warrants that, at the date of first power deliveries from Seller's *Facility*[1] and during the *term of agreement*, its *Facility* shall meet the qualifying facility requirements established as of the effective date of this Agreement by the Federal Energy Regulatory Commission's rules (18 Code of Federal Regulations 292) implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 796, et seq.).

Article 2 Commitment of Parties

The prices to be paid Seller for energy and/or capacity delivered pursuant to this Agreement have wholly or partly been fixed at the time of execution. Actual avoided costs at the time of energy and/or capacity deliveries may be substantially above or below the prices fixed in this Agreement. Therefore, the Parties expressly commit to the prices fixed in this Agreement for the applicable period of performance and shall not seek to or have a right to renegotiate such prices for any reason. As part of its consideration for the benefit of fixing part or all of the energy and/or capacity prices under this Agreement, Seller waives any and all rights to judicial or other relief from its obligations and/or prices set forth in Appendices B, D, and E, or modification of any other term or provision for any reasons whatsoever.

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[1] Italics identifies those terms which are defined in Section A-1 of Appendix A.

This Agreement contains certain provisions which set forth methods of calculating damages to be paid to PGandE in the event Seller fails to fulfill certain performance obligations. The inclusion of such provisions is not intended to create any express or implied right in Seller to terminate this Agreement prior to the expiration of the *term of agreement*. Termination of this Agreement by Seller prior to its expiration date shall constitute a breach of this Agreement and the damages expressly set forth in this Agreement shall not constitute PGandE's sole remedy for such breach.

Article 3 Purchase of Power

(a) Seller shall sell and deliver and PGandE shall purchase and accept delivery of capacity and energy at the *voltage level* of ____ kV.

(b) Seller shall provide capacity and energy from its _____ kw *Facility* located at _____.
[Nameplate rating of generator(s)]

(c) The *scheduled operation date* of the *Facility* is _____.
[Date]

At the end of each calendar quarter Seller shall give written notice to PGandE of any change in the *scheduled operation date*.

(d) Seller shall limit the *Facility's* actual rate of delivery into the PGandE system to ____ kw.

(e) The primary energy source for the *Facility* is _____.

Article 4 Energy Price

PGandE shall pay Seller for its _____[1] under the energy payment option checked below:[2]

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[1] Insert either "*net energy output*" or "*surplus energy output*" to show the energy sale option selected by Seller.

[2] Option 2 is not available to oil or gas-fired cogenerators.

Energy Payment Option 1—Forecasted Energy Prices

During the *fixed price period*, Seller shall be paid for energy delivered at prices equal to ____[3] percent of the prices set forth in Table B-1, Appendix B, plus ____[4] percent of PGandE's *full short-run avoided operating costs.*

For the remaining years of the *term of agreement*, Seller shall be paid for energy delivered at prices equal to PGandE's *full short-run avoided operating costs.*

If Seller's *Facility* is not an oil or gas-fired cogeneration facility, Seller may convert from Energy Payment Option 1 to Energy Payment Option 2 and be subject to the conditions therein, provided that Seller shall not change the percentage of energy prices to be based on PGandE's *full short-run avoided operating costs.* Such conversion must be made at least 90 days prior to the date of initial energy deliveries and must be made by written notice in accordance with Section A-17, Appendix A.

Energy Payment Option 2—Levelized Energy Prices

During the *fixed price period,* Seller shall be paid for energy delivered at prices equal to ____[5] percent of the levelized energy prices set forth in Table B-2, Appendix B for the year in which energy deliveries begin and *term of agreement*, plus ____[6] percent of PGandE's *full short-run avoided operating costs.* During the *fixed price period*, Seller shall be subject to the conditions and terms set forth in Appendix B, Energy Payment Option 2.

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[3] Insert either 0, 20, 40, 60, 80, or 100, at Seller's option. If Seller's *Facility* is an oil or gas-fired cogeneration facility, either 0 or 20 must be inserted

[4] Insert the difference between 100 and the percentage selected under footnote 2 above.

[5] Insert either 20, 40, 60, 80, or 100, at Seller's option.

[6] Insert the difference between 100 and the percentage selected under footnote 4 above.

For the remaining years of the *term of agreement*, Seller shall be paid for energy delivered at prices equal to PGandE's *full short-run avoided operating costs.*

Seller may convert from Energy Payment Option 2 to Energy Payment Option 1, provided that Seller shall not change the percentage of energy prices to be based on PGandE's *full short-run avoided operating costs.* Such conversion must be made at least 90 days prior to the date of initial energy deliveries and must be made by written notice in accordance with Section A-17, Appendix A.

Energy Payment Option 3—Incremental Energy Rate

Beginning with the date of initial energy deliveries and continuing until _____,[7] Seller shall be paid monthly for energy delivered at prices equal to PGandE's *full short-run avoided operating costs,* provided that adjustments shall be made annually to the extent set forth in Appendix B, Energy Payment Option 3.

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[7] Specified by Seller. Must be December 31, 1998 or prior.

The Incremental Energy Rate Band Widths specified by Seller in Table I below shall be used in determining the annual adjustment, if any.

TABLE I

Year	Incremental Energy Rate Band Widths (must be multiples of 100 or zero)
1984	
1985	
1986	
1987	
1988	
1989	
1990	
1991	
1992	
1993	
1994	
1995	
1996	
1997	
1998	

After , Seller shall be paid for energy delivered at prices equal to PGandE's *full short-run avoided operating costs.*

Article 5 Capacity Election and Capacity Price

Seller may elect to deliver either *firm capacity* or *as-delivered capacity,* and Seller's election is indicated below:

Firm capacity—____ kW for ____ years from the *firm capacity availability date* with payment determined in accordance with Appendix E. Except for hydroelectric facilities, PGandE shall pay Seller for capacity delivered in excess of *firm capacity* on an *as-delivered capacity* basis in accordance with As-Delivered Capacity Payment Option __ set forth in Appendix D.

OR

As-delivered capacity with payment determined in accordance with As-Delivered Capacity Payment Option __ set forth in Appendix D.

Article 6 Loss Adjustment Factors

Capacity Loss Adjustment Factors shall be as shown in Appendix D and Appendix E, dependent upon Seller's capacity election set forth in Article 5 of this Agreement.

Energy Loss Adjustment Factors shall be considered as unity for all energy payments related to Energy Payment Options 1 and 2 set forth in Appendix B for the entire *fixed price period* of this Agreement, except for the percentage of payments that Seller elected in Article 4 to have calculated based on PGandE's *full short-run avoided operating costs.* Energy Loss Adjustment Factors for all payments related to PGandE's *full short-term avoided operating* costs are subject to *CPUC* rulings for the entire *term of agreement.*

Article 7 Curtailment

Seller has two options regarding possible curtailment by PGandE of Seller's deliveries, and Seller's selection is indicated below:

Curtailment Option A—Hydro Spill and Negative Avoided Cost

Curtailment Option B—Adjusted Price Period

The two options are described in Appendix C.

Article 8 Retroactive Application of CPUC Orders

Pursuant to Ordering Paragraph 1(f) of *CPUC* Decision No. 83-09-054 (September 7, 1983), after the effective date of the *CPUC's* Application 82-03-26 decision relating to 1) line loss factors; 2) interconnection provisions involving future lines and system upgrades; and 3) insurance, Seller has the option to retain

the relevant terms of this Agreement or have the results of that decision incorporated into this Agreement. To retain the terms herein, Seller shall provide written notice to PGandE within 30 days after the effective date of the relevant *CPUC* decision on Application 82-03-26. Failure to provide such notice will result in the amendment of this Agreement to comply with that decision.

As soon as practicable following the issuance of a decision in Application 82-03-26, PGandE shall notify Seller of the effective date thereof and its results.

Article 9 Notices

All written notices shall be directed as follows:

To PGandE: Pacific Gas and Electric Company
Attention: Vice President—Electric Operations
77 Beale Street
San Francisco, CA 94106

To Seller: _____
_____
_____
_____
_____

Article 10 Designated Switching Center

The ***designated PGandE switching center*** shall be, unless changed by PGandE:

_____
(Name)

_____
(Location)

_____
(Phone Number)

Article 11 Terms and Conditions

This Agreement includes the following appendices which are attached and incorporated by reference:

Appendix A—GENERAL TERMS AND CONDITIONS
Appendix B—ENERGY PAYMENT OPTIONS
Appendix C—CURTAILMENT OPTIONS
Appendix D—AS-DELIVERED CAPACITY
Appendix E—FIRM CAPACITY

Article 12 Term of Agreement

This Agreement shall be binding upon execution and remain in effect for _____ years[1] from the date of initial deliveries; provided, however, that it shall terminate if energy deliveries do not start within five years of the effective date.

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[1] The minimum contract term is 15 years and the maximum contract term is 30 years.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives and it is effective as of the last date set forth below.

_____

(SELLER)

BY: _____

_____

(Type Name)

TITLE: _____

DATE SIGNED: _____

PACIFIC GAS AND ELECTRIC COMPANY

BY: _____

_____

(Type Name)

TITLE: _____

DATE SIGNED: _____

Appendix A

General Terms and Conditions

A-1 Definitions

Whenever used in this Agreement, appendices, and attachments hereto, the following terms shall have the following meanings:

Adjusted firm capacity price—The $/kW-year purchase price for *firm capacity* from Table E-2, Appendix E for the period of Seller's actual performance.

As-delivered capacity—Capacity delivered to PGandE in excess of *firm capacity* or in lieu of a *firm capacity* commitment.

CPUC—The Public Utilities Commission of the State of California.

Current firm capacity price—The $/kW-year capacity price from PGandE's *firm capacity price schedule* effective at the time PGandE derates the *firm capacity* pursuant to Section E-4(b), Appendix E or Seller terminates performance under this Agreement, for a term equal to the period from the date of deration or termination to the end of the *term of agreement*.

Designated PGandE switching center—That switching center or other PGandE installation identified in Article 10.

Facility—That generation apparatus described in Article 3 and all associated equipment owned, maintained, and operated by Seller.

Firm capacity—That capacity, if any, identified as firm in Article 5 except as otherwise changed as provided herein.

Firm capacity availability date—The day following the day during which all features and equipment of the *Facility* are demonstrated to PGandE's satisfaction to be capable of operating simultaneously to deliver *firm capacity* continuously into PGandE's system as provided in this Agreement.

Firm capacity price—The price for *firm capacity* applicable for the *firm capacity availability date* and the number of years of *firm capacity* delivery from either the *firm capacity price schedule,* Table E-2, Appendix E, or the successor to Table E-2 in effect on the *firm capacity availability date,* whichever is higher.

Firm capacity price schedule—The periodically published schedule of the $/kW-year prices that PGandE offers to pay for *firm capacity.* See Table E-2, Appendix E.

Fixed price period—The period during which forecasted or levelized energy prices, and/or forecasted *as-delivered capacity* prices, are in effect; defined as the first five years of the *term of agreement* if the *term of agreement* is 15 or 16 years; the first six years of the *term of agreement* if the *term of agreement* is 17, 18, or 19 years; or the first ten years of the *term of agreement* if the *term of agreement* is anywhere from 20 through 30 years.

Forced outage—Any outage resulting from a design defect, inadequate construction, operator error or a breakdown of the mechanical or electrical equipment that fully or partially curtails the electrical output of the *Facility.*

Full short-run avoided operating costs—*CPUC*-approved costs which are the basis of PGandE's published energy prices. PGandE's current energy price calculation is shown in Table B-5, Appendix B. PGandE's published off-peak hours' prices shall be adjusted, as appropriate, if Seller has selected Curtailment Option B.

Interconnection facilities—All means required and apparatus installed to interconnect and deliver power from the *Facility* to the PGandE system including, but not limited to, connection, transformation, switching, metering, communications, and safety equipment such as equipment required to protect (1) the PGandE system and its customers from faults occurring at the *Facility,* and (2) the *Facility* from faults occurring on the PGandE system or on the systems of others to which the PGandE system is directly or indirectly connected. *Interconnection facilities* also include any necessary

additions and reinforcements by PGandE to the PGandE system required as a result of the interconnection of the *Facility* to the PGandE system.

Net energy output—The *Facility's* gross output in kilowatt-hours less *station use* and transformation and transmission losses to the point of delivery into the PGandE system.

Prudent electrical practices—Those practices, methods, and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to design and operate electric equipment lawfully and with safety, dependability, efficiency, and economy.

Scheduled operation date—The day specified in Article 3(c) when the *Facility* is, by Seller's estimate, expected to produce energy that will be available for delivery to PGandE.

Special facilities—Those parts of the *interconnection facilities* furnished by PGandE at Seller's request, metering and data processing equipment, and those additions and reinforcements to the PGandE system which are needed to accommodate the maximum delivery of energy and capacity from the *Facility* as provided in this Agreement. All *special facilities* shall be furnished at Seller's expense pursuant to PGandE's electric Rule No. 21 by a separate agreement.

Station use—Energy used to operate the *Facility's* auxiliary equipment. The auxiliary equipment includes, but is not limited to, forced and induced draft fans, cooling towers, boiler feed pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

Surplus energy output—The *Facility's* group output, in kilowatt-hours, less *station use,* and any other use by Seller, and transformation and transmission losses to the point of delivery into the PGandE system.

Term of agreement—The number of years this Agreement will remain in effect from the date of initial energy deliveries, as provided in Article 12.

Voltage level—The voltage at which the *Facility* interconnects with the PGandE system, measured at the point of delivery.

A-2 Construction

A-2.1 Land Rights

Seller hereby grants to PGandE all necessary rights of way and easements, including adequate and continuing access rights on property of Seller, to install, operate, maintain, replace, and remove the *special facilities.* Seller agrees to execute such other grants, deeds, or documents as PGandE may require to enable it to record such rights of way and easements. If any part of PGandE's equipment is to be installed on property owned by other than Seller, Seller shall, at its own cost and expense, obtain from the owners thereof all necessary rights of way and easements, in a form satisfactory to PGandE, for the construction, operation, maintenance, and replacement of PGandE's equipment upon such property. If Seller is unable to obtain such rights of way and easements, Seller shall reimburse PGandE for all costs incurred by PGandE in obtaining them. PGandE shall at all times have the right of ingress to and egress from the *Facility* at all reasonable hours for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to PGandE by law or its tariff schedules.

A-2.2 Design, Construction, Ownership, and Maintenance

(a) Seller shall design, construct, install, own, operate, and maintain all *interconnection facilities,* except *special facilities,* to the point of interconnection with the PGandE system as required for PGandE to recieve capacity and energy from the *Facility.* The Facility and *interconnection facilities* shall meet all requirements of applicable codes and all standards of *prudent electrical practices* and shall be managed in a safe and prudent manner.

(b) Seller shall submit to PGandE all specifications for the *interconnection facilities* (except *special facilities*) and, at PGandE's option, the *Facility,* for review and written

acceptance prior to their release for construction purposes. PGandE's review and acceptance of these specifications shall not be construed as confirming or endorsing the design or as warranting their safety, durability, or reliability. PGandE shall not, by reason of such review or lack of review, be responsible for strength, details of design, adequacy, or capacity of equipment built pursuant to such specifications, nor shall PGandE's acceptance be deemed to be an endorsement of any of such equipment. Seller shall change the *interconnection facilities* as may be reasonably required by PGandE to meet changing requirements of the PGandE system.

(c) In the event it is necessary for PGandE to install *interconnection facilities* for the purpose of this Agreement, they shall be installed as *special facilities.*

A-2.3 Meter Installation

(a) PGandE shall specify, provide, install, own, operate, and maintain as *special facilities* all metering and data processing equipment for the registration and recording of energy and other related parameters which are required for the reporting of data to PGandE and for computing the payment due Seller from PGandE.

(b) Seller shall provide, construct, install, own and maintain at Seller's expense all that is required to accommodate the metering and data processing equipment, such as, but not limited to, metal-clad switchgear, switchboards cubicles, metering panels, enclosures, conduits, rack structures, and equipment mounting pads.

A-3 Operation

A-3.1 Inspection and Approval

Seller shall not operate the *Facility* in parallel with PGandE's system until an authorized PGandE representative has inspected the *interconnection facilities,* and PGandE has given written approval to begin parallel operation.

A-3.2 *Facility* Operation and Maintenance

Seller shall operate and maintain its *Facility* according to *prudent electrical practices,* applicable laws, orders, rules, and tariffs and shall provide such reactive power support as may be reasonably required by PGandE to maintain system voltage level and power factor. Seller shall operate the *Facility* at the power factor or voltage levels prescribed by PGandE's system dispatcher or designated representative if Seller fails to provide reactive power support, PGandE may do so at Seller's expense.

A-3.3 Point of Delivery

Seller shall deliver the energy at the point where Seller's electrical conductors contact PGandE's existing system or at such other point as the Parties may agree in writing.

A-3.4 Operating Communications

(a) Seller shall maintain operating communications with the *designated PGandE switching center.* The operating communications shall include, but not be limited to, system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, levels of operating voltage or power factors and daily capacity and generation reports.

(b) Seller shall keep a daily operations log for each generating unit which shall include information on unit availability, maintenance outages, circuit breaker trip operations requiring a manual reset, and any significant event related to the operation of the *Facility.*

(c) If Seller makes deliveries greater than one megawatt, Seller shall measure and register on a graphic recording device power in kW and voltage in kV at a location with the *Facility* agreed to by both parties.

(d) If Seller makes deliveries greater than one and up to and including ten megawatts, Seller shall report to the *designated PGandE switching center,* twice a day at agreed upon times for the current day's operation, the

hourly readings in kW of capacity delivered and the energy in kWh delivered since the last report.

(e) If Seller makes deliveries of greater than ten megawatts, Seller shall telemeter the delivered capacity and energy information, including real power in kW, reactive power in kVAR, and energy in kWh to a switching center selected by PGandE. PGandE may also require Seller to telemeter transmission kW, kVAR, and kV data depending on the number of generators and transmission configuration. Seller shall provide and maintain the data circuits required for telemetering. When telemetering is inoperative, Seller shall report daily the capacity delivered each hour and the energy delivered each day to the *designated PGandE switching center.*

A-3.5 Meter Testing and Inspection

(a) All meters used to provide data for the computation of the payments due Seller from PGandE shall be sealed, and the seals shall be broken only by PGandE when the meters are to be inspected, tested, or adjusted.

(b) PGandE shall inspect and test all meters upon their installation and annually thereafter. At Seller's request and expense, PGandE shall inspect or test a meter more frequently. PGandE shall give reasonable notice to Seller of the time when any inspection or test shall take place, and Seller may have representatives present at the test or inspection. If a meter is found to be inaccurate or defective, PGandE shall adjust, repair, or replace it at its expense in order to provide accurate metering.

A-3.6 Adjustments to Meter Measurements

If a meter fails to register, or if the measurement made by a meter during a test varies by more than two percent from the measurement made by the standard meter used in the test, an adjustment shall be made correcting all measurements made by the inaccurate meter for—(1) the actual period during which inaccurate measurements were made, if the period can be deter-

mined, or if not, (2) the period immediately preceding the test of the meter equal to one-half the time from the date of the last previous test of the meter, provided that the period covered by the correction shall not exceed six months.

A-4 Payment

PGandE shall mail to Seller not later than 30 days after the end of each monthly billing period (1) a statement showing the energy and capacity delivered to PGandE during on-peak, partial-peak, and off-peak periods during the monthly billing period, (2) PGandE's computation of the amount due Seller, and (3) PGandE's check in payment of said amount. If within 30 days of receipt of the statement Seller does not make a report in writing to PGandE of an error, Seller shall be deemed to have waived any error in PGandE's statement, computation, and payment, and they shall be considered correct and complete.

A-5 Adjustments of Payments

(a) In the event adjustments to payments are required as a result of inaccurate meters, PGandE shall use the corrected measurements described in Section A-3.6 to recompute the amount due from PGandE to Seller for the capacity and energy delivered under this Agreement during the period of inaccuracy.

(b) The additional payment to Seller or refund to PGandE shall be made within 30 days of notification of the owing Party of the amount due.

A-6 Access to Records

Each Party, after giving reasonable written notice to the other Party, shall have the right of access to all metering and related records including operations logs of the *Facility*.

A-7 Interruption of Deliveries

PGandE shall not be obligated to accept or pay for and may require Seller to interrupt or reduce deliveries of energy (1) when necessary in order to construct, install, maintain, repair, replace,

remove, investigate, or inspect any of its equipment or any part of its system, or (2) if it determines that interruption or reduction is necessary because of PGandE system emergencies, forced outages, force majeure, or compliance with *prudent electrical practices;* provided that PGandE shall not interrupt deliveries pursuant to this section in order to take advantage, or make purchases, of less expensive energy elsewhere. Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

A-8 Force Majeure

(2) The term force majeure as used herein means unforeseeable causes, other than *forced outages,* beyond the reasonable control of and without the fault or negligence of the Party claiming force majeure, including but not limited to, acts of God, labor disputes, sudden actions of the elements, and actions by federal, state, municipal, or any other government agency.

(b) If either Party because of force majeure is rendered wholly or partly unable to perform its obligations under this Agreement, that Party shall be excused from whatever performance is affected by the force majeure to the extent so affected provided that:

(1) the non-performing Party, within two weeks after the occurrence of the force majeure, gives the other Party written notice describing the particulars of the occurrence,

(2) the suspension of performance is of no greater scope and of no longer duration than is required by the force majeure,

(3) the non-performing Party uses its best efforts to remedy its inability to perform (this subsection shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts,

lockouts or other labor disputes shall be at the sole discretion of the Party having the difficulty),

(4) when the non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect, and

(5) capacity payments during such periods of force majeure on Seller's part shall be governed by Section E-2(c), Appendix E.

A-9 Indemnity

Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and property damages including property of either Party resulting from or arising out of (1) the engineering, design, construction, maintenance, or operation of, or (2) the making of replacements, additions, or betterments to, the indemnitor's facilities. This indemnity and save harmless provision shall apply notwithstanding the active or passive negligence of the indemnitee. Neither Party shall be indemnified hereunder for its liability or loss resulting from its sole negligence, or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees, that may be incurred by the other Party in enforcing this indemnity.

A-10 Liability; Dedication

(a) Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a Party to it. Neither Party shall be liable to the other Party for consequential damages.

(b) Each Party shall be responsible for protecting its facilities from possible damage by reason of electrical disturbances or faults caused by the operation, faulty operation, or nonoperation of the other Party's facilities,

and such other Party shall not be liable for any such damages so caused.

(c) No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public or affect the status of PGandE as an independent public utility corporation or Seller as an independent individual or entity and not a public utility.

A-11 Several Obligations

Except where specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or impose a trust of partnership duty, obligation, or liability on or with regard to either Party. Each Party shall be liable individually and severally for its own obligations under this Agreement.

A-12 Non-Waiver

Failure to enforce any right or obligation by either Party with respect to any matter arising in connection with this Agreement shall not constitute a waiver as to that matter or any other matter.

A-13 Assignment

Neither Party shall voluntarily assign its rights nor delegate its duties under this Agreement, or any part of such rights or duties, without the written consent of the other Party, except in connection with the sale or merger of a substantial portion of its properties. Any such assignment or delegation made without such written consent shall be null and void. Consent for assignment shall not be withheld unreasonably. Such assignment shall include, unless otherwise specified therein, all of Seller's rights to any refunds which might become due under this Agreement.

A-14 Captions

All indexes, titles, subject headings, section titles, and similar items are provided for the purpose of reference and convenience and are not intended to affect the meaning of the contents or scope of this Agreement.

A-15 Choice of Laws

This Agreement shall be interpreted in accordance with the laws of the State of California, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

A-16 Governmental Jurisdiction and Authorization

Seller warrants that the *Facility* and *interconnection facilities,* except special facilities, shall at all times conform to all applicable laws and regulations, and Seller shall obtain any governmental authorizations and permits required for the construction and operation thereof. If at any time Seller does not hold such authorizations and permits PGandE may refuse to accept deliveries of power hereunder.

A-17 Notices

Any notice, demand, or request required or permitted to be given by either Party to the other, and any instrument required or permitted to be tendered or delivered by either Party to the other, shall be in writing (except as provided in Section E-3) and so given, tendered, or delivered, as the case may be, by depositing the same in any United States Post Office with postage prepaid for transmission by certified mail, return receipt requested, addressed to the Party, or personally delivered to the Party, at the address in Article 9 of this Agreement. Changes in such designation may be made by notice similarly given.

A-18 Insurance

A-18.1 Workers' Compensation

Seller shall furnish PGandE a certificate of workers' compensation or self-insurance indicating compliance with the Labor Code

of California, including Employer's Liability insurance with a minimum of $2,000,000 for injury or death of any one person. This certificate shall provide for 30-days' written notice to PGandE prior to cancellation, termination, alteration, or material change of such insurance.

A-18.2 Comprehensive General and Comprehensive automobile Liability Coverage

(a) Seller shall maintain during the performance hereof, Comprehensive General Liability and Comprehensive Automobile Liability of not less than $3,000,000 combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence

(b) Comprehensive General Liability shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations. Comprehensive Automobile Liability shall include coverage for Owned, Hired, and Non-Owned automobiles.

(c) Such insurance, by endorsement to the policy(ies), shall include PGandE as an additional insured insofar as work performed by Seller for PGandE is concerned, shall contain a severability of interest clause, shall provide that PGandE shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for payment of premium for such insurance, and shall provide for 30-days' written notice to PGandE prior to cancellation, termination, alteration, or material change of such insurance.

A-18.3 Additional Insurance Provisions

(a) Evidence of coverage described above in Sections A-18.1 and A-18.2 shall state that coverage provided is

primary and is not excess to or contributing with any insurance or self-insurance maintained by PGandE.

(b) PGandE shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.

(c) Seller shall furnish the required certificates and endorsements to PGandE prior to the date construction of the *Facility* begins or the effective date of this Agreement, whichever is later.

(d) All insurance certificates, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

PACIFIC GAS AND ELECTRIC COMPANY
Attention: Manager—Insurance Department
77 Beale Street
San Francisco, CA 94106

APPENDIX B
ENERGY PAYMENT OPTIONS

Energy Payment Option 1—Forecasted Energy Prices

Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during each year of the *fixed price period* shall include the appropriate prices for such year in Table B-1, multiplied by the percentage Seller has specified in Article 4. If Seller has selected Curtailment Option B in Article 7, the forecasted off-peak hours' energy prices listed in Table B-1 shall be adjusted upward by 7.7% for Period A and 9.6% for Period B.

TABLE B-1
Forecasted Energy Price Schedule

Year of Energy Deliveries	Forecasted Energy Prices*, ¢/kWh						
	Period A			Period B			Weighted Annual Average
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.36	5.12	4.94	5.44	5.31	5.19	5.18
1984	5.66	5.40	5.22	5.74	5.61	5.48	5.47
1985	5.75	5.48	5.30	5.83	5.69	5.56	5.55
1986	5.99	5.72	5.52	6.08	5.94	5.80	5.79
1987	6.38	6.08	5.88	6.47	6.32	6.17	6.16
1988	6.94	6.62	6.39	7.03	6.87	6.71	6.70
1989	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1990	8.12	7.74	7.48	8.23	8.04	7.85	7.84
1991	8.64	8.24	7.96	8.75	8.56	8.35	8.34
1992	9.33	8.90	8.60	9.46	9.24	9.02	9.01
1993	10.10	9.63	9.30	10.23	10.00	9.76	9.75
1994	10.91	10.41	10.06	11.06	10.81	10.55	10.54
1995	11.79	11.25	10.87	11.96	11.68	11.40	11.39
1996	12.67	12.09	11.68	12.85	12.56	12.25	12.24
1997	13.61	12.98	12.54	13.79	13.48	13.15	13.14

* These prices are differentiated by the time periods as defined in Table B-4.

Energy Payment Option 2—Levelized Energy Prices

Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during the *fixed price period* shall include the appropriate prices set forth in Table B-2 for the year in which energy deliveries begin and *term of agreement*, multiplied by the percentage Seller has specified in Article 4. If Seller has selected Curtailment Option B in Article 7, the levelized off-peak hours' energy prices listed in Table B-2 shall be adjusted upward by 7.7% for Period A and 9.6% for Period B. The discount specified in (c)(vi) below, if applicable, will be applied to the energy payments during the *fixed price period.*

During the *fixed price period*, Seller shall be subject to the following conditions and terms:

(a) Minimum Damages

The Parties agree that the levelized energy prices which PGandE pays Seller for the energy which Seller delivers to PGandE is based on the agreed value to PGandE of Seller's energy deliveries during the entire *fixed price period.* In the event PGandE does not receive such full performance by reason of a termination, Seller shall pay PGandE an amount based on the difference between the net present values, at the time of termination, of the payments Seller would receive at the forecasted energy prices in Table B-1 and the payments Seller would receive at the levelized energy prices, for the remaining years of the *fixed price period.* This amount shall be calculated by assuming that Seller continued to generate for the remaining years of the *fixed price period* at a level equal to the average annual energy generation during the period of performance, and by applying the weighted annual average levelized price applicable to Seller's *Facility* and the weighted annual average forecasted energy prices in Table B-1 for the remaining years of the *fixed price period.* The following formula shall be used to make this calculation:

$$P = \sum_{n=1}^{Y} \frac{(F_n)\ (A)\ (W)}{(1.15)^n} - \sum_{n=1}^{Y} \frac{(L)\ (A)\ (W)}{(1.15)^n}$$

where:

P = amount due PGandE

Y = number of years remaining in the *fixed price period*

F_n = Weighted annual average forecasted energy price in the nth year after the breach, failure to perform, or expiration of security, as shown in Table B-1 for the corresponding calendar year

L = weighted annual average levelized energy price applicable to Seller's *Facility*

A = average annual energy generation by Seller during the period of performance

n = summation index; refers to the nth year following termination

W = percent of Seller's energy payments based on the levelized energy prices, as specified in Article 4

(b) Performance Requirements

Seller shall operate and maintain the *Facility* in accordance with *prudent electrical practices* in order to maximize the likelihood that the *Facility's* output as delivered to PGandE during the part of the *fixed price period* when the levelized price is below the forecasted price ("last part") shall equal or exceed 70% of the *Facility's* output during the part of the *fixed price period* when the levelized price is above the forecasted price ("first part"). In the event that the *Facility's* output during any year or series of years in the last part of the *fixed price period* is less than 70% of the average annual production during the first part of the *fixed price period,* PGandE may, at its discretion (taking into consideration events occurring during such year or series of years such as curtailment by PGandE, Seller's choice not to operate during adjusted price periods, or scheduled maintenance including major overhauls, and the probability that Seller's future performance will be adequate), either request payment from Seller or immediately draw, on the security posted, up to the amount equal to

$$P \times \frac{A\text{-}B}{A,}$$ where:

P and A are as defined in Section (a) above.

B = Seller's average annual energy generation during the year or series of years in which the 70% performance requirement was not met.

PGandE shall *not* request payment from Seller or draw on the security posted if the *Facility's* output during the last part of the fixed price period falls below 70% of the average annual energy generation during the first part of the *fixed price period* solely because of force majeure as defined in Section A-8, Appendix A or a lack of or limited availability of the primary energy resource of the *Facility,* if such energy resource is wind, water, or sunlight.

(c) Security

(1) As security for amounts which Seller may be obligated to pay PGandE pursuant to Sections (a) and (b) above, Seller shall provide and maintain one or more of the following in an amount as described in Section (c)(2) below.

(i) An irrevocable bank letter of credit delivered to and in favor of PGandE with terms acceptable to PGandE.

(ii) A payment bond providing for payment to PGandE in the event of any failure to meet the performance requirements set forth in Section (b) above or breach of this Agreement by Seller. Such bond shall be issued by a surety company acceptable to PGandE and shall have terms acceptable to PGandE.

(iii) Fully paid up, noncancellable Project Failure Insurance made payable to PGandE with terms of such policy(ies) acceptable to PGandE.

(iv) A performance bond providing for payment to PGandE in the event of any failure to meet the performance requirements set forth in Section (b) above or breach of this Agreement by Seller. Such bond shall be issued by a surety company acceptable to PGandE and shall have terms acceptable to PGandE.

(v) A corporate guarantee of payment to PGandE which PGandE deems, in its sole discretion, to provide at least the same quality of security as subsections (i) through (iv) above.

(vi) Other forms of security which PGandE does not deem to be equivalent security to those listed in subsections (i) through (v) above, and which PGandE, in its sole discretion, deems adequate. Such other forms of security may include, for example, a corporate guarantee or a lien, mortgage or deed of trust on the *Facility* or land upon which it is located. A 1.5% discount will be applied against the levelized energy price portion of PGandE's payments to Seller during the *fixed price period* if this type of security is provided.

(2) (i) Commencing 90 days prior to the *scheduled operation date* and continuing until December 1 of the following calendar year, security as described in Section (c)(1) above shall be in place in an amount calculated in accordance with the formula set forth in Section (a) above, assuming Seller delivered energy through the end of the following calendar year and then terminated this Agreement. For purposes of determining the required amount of security, it shall be assumed that Seller's deliveries through the end of the following calendar year would equal $R \times C \times H$, where:

R = nameplate rating, in kWh, of the *Facility*

C = estimated capacity factor of the *Facility,* which shall be established by mutual agreement of the Parties at the time of execution of this Agreement

H = number of hours from the *scheduled operation date* through the end of the following calendar year

(ii) In the second calendar year of operation and each year thereafter until the end of the *fixed price period*, from December 1 through December 1 of the following year, security shall be in an amount calculated by the formula set forth in Section (a) above assuming Seller continued to deliver energy in each month through the end of the following calendar year, at a level equal to the average monthly energy deliveries to date, and then terminated this Agreement.

(3) Security must be maintained throughout the *fixed price period* as specified above. Any security with a fixed expiration date must be renewed by Seller prior to that date. If such security is not renewed at least 30 days prior to its expiration, PGandE may, at its discretion, either request payment from Seller or immediately draw on the security posted, up to the amount calculated in accordance with the formula set forth in Section (a) above.

(4) If, at any time during the *fixed price period*, PGandE believes Seller is in material breach of this Agreement, PGandE shall so notify Seller in writing and Seller must remedy such breach within a reasonable period of time. If Seller does not so remedy, PGandE may, at its discretion, either request payment from Seller or immediately draw upon the security posted, up to the amount calculated in accordance with the formula set forth in Section (a) above, provided that if during Seller's period to remedy, Seller disputes PGandE's conclusion that Seller is in material breach, and PGandE elects to draw upon the security, the amount drawn upon by PGandE shall be deposited in an interest earning escrow account and held in such account until the dispute is resolved in accordance with Section (c)(5) below.

(5) Upon the written request of either Party, any controversy or dispute between the Parties concerning Section (c)(4) above shall be subject to arbitration in accordance with the provisions of the California Arbitration Act, Sections 1280-1294.2 of the California Code of Civil Procedure except as provided otherwise in this section. Either Party may demand arbitration by first giving written notice of the existence of a dispute and then within 30 days of such notice giving a second written notice of the demand for arbitration.

Within ten days after receipt of the demand for arbiration, each Party shall appoint one person, who shall not be an employee of either Party, to hear and determine the dispute. After both arbitrators have been appointed, they shall within five (5) days select a third arbitrator.

The arbitration hearing shall take place in San Francisco, California, within 30 days of the appointment of the arbitrators, at such time and place as they select. The arbitrators shall give written notice of the time of the hearing to both Parties at least ten days prior to the hearing. The arbitrators shall not be authorized to alter, extend, or modify the terms of this Agreement. At the hearing, each Party shall submit a proposed written decision, and any relevant evidence may be presented. The decision of the arbitrators must consist of selection of one of the two proposed decisions, in its entirety.

The decision of any two arbitrators shall be binding and conclusive as to disputes relating to Section (c)(4) only. Upon determining the matter, the arbitrators shall promptly execute and acknowledge their decision and deliver a copy to each Party. A judgment confirming the award may be rendered by any superior court having jurisdiction. Each Party shall bear its own arbitration costs and expenses, including the cost of the arbitrator it selected, and the costs and expenses of the third arbitrator shall be divided equally between both Parties, except as provided otherwise elsewhere in this Agreement.

Pending resolution of any controversy or dispute hereunder, performance by each Party shall continue so as to maintain the status quo prior to notice of such controversy or dispute. Resolution of the controversy or dispute shall include payment of any interest accrued in the escrow account.

TABLE B-2

Levelized Energy Price Schedule

For a *term of agreement* of 15-16 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						
	Period A			Period B			Weighted Annual Average
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.76	5.50	5.31	5.85	5.71	5.58	5.57
1984	6.06	5.78	5.58	6.14	6.00	5.86	5.85
1985	6.41	6.11	5.91	6.50	6.35	6.20	6.19
1986	6.85	6.54	6.32	6.95	6.79	6.63	6.62
1987	7.37	7.03	6.79	7.47	7.30	7.13	7.12
1988	7.96	7.60	7.34	8.07	7.89	7.70	7.69

For a *term of agreement* of 17-19 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						
	Period A			Period B			Weighted Annual Average
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.90	5.63	5.44	5.98	5.84	5.71	5.70
1984	6.23	5.95	5.74	6.32	6.18	6.03	6.02
1985	6.60	6.30	6.08	6.69	6.53	6.38	6.37
1986	7.06	6.73	6.51	7.16	7.00	6.83	6.82
1987	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1988	8.21	7.83	7.57	8.32	8.13	7.94	7.93

* These prices are differentiated by the time periods as defined in Table B-4.

For a *term of agreement* of 20-30 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						
	Period A			Period B			Weighted Annual Average
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	6.49	6.20	5.98	6.58	6.43	6.28	6.27
1984	6.90	6.58	6.35	6.99	6.83	6.67	6.66
1985	7.34	7.00	6.76	7.44	7.27	7.10	7.09
1986	7.88	7.51	7.26	7.99	7.81	7.62	7.61
1987	8.49	8.10	7.82	8.61	8.41	8.21	8.20
1988	9.16	8.74	8.44	9.29	9.08	8.86	8.85

* These prices are differentiated by the time periods as defined in Table B-4.

Energy Payment Option 3—Incremental Energy Rate

During the period specified in Article 4, annual adjustments to Seller's energy payments shall be made as described below.

At the end of each calendar year, the Derived Incremental Energy Rate (with units expressed in Btu/kWh) will be calculated as follows:

$$\text{Derived Incremental Energy Rate (DIER)} = \frac{B}{A \times C}$$

where:

A = the total kWh delivered by Seller during the calendar year, excluding any kWh delivered when Seller was asked to curtail deliveries under Curtailment Option A *or* when Seller was asked to take adjusted prices under Curtailment Option B

B = the total dollars paid for the energy described for A above

C = the weighted average price paid during the calendar year by PGandE's Electric Department for oil and natural gas for PGandE's fossil steam plants, expressed in S/Btu on a gas Btu basis

If the DIER is between the upper and lower Incremental Energy Rate Bounds specified for that year in Table B-3 for the curtailment option selected by Seller, no additional payment is due either Party.

If the DIER is below the lower Incremental Energy Rate Bound, PGandE shall pay Seller an amount calculated as follows:

$$P_S = (\text{Lower Incremental Energy Rate Bound} - \text{DIER})\ (A)\ (C)$$

where:

P_S = additional payment due Seller

DIER = Derived Incremental Energy Rate

PGandE shall add this payment to the first payment made to Seller following the calculation.

If the DIER is above the upper Incremental Energy Rate Bound, Seller shall pay PGandE an amount calculated as follows:

$$P_B = (\text{DIER} - \text{Upper Incremental Energy Rate Bound}) \quad (A)\ (C)$$

where:

P_B = amount due PGandE
DIER = Derived Incremental Energy Rate

This amount shall be deducted from the first payment made to Seller following the calculation. If there is any remaining amount due PGandE, PGandE may, at its option, invoice Seller with such payment due within 30 days or deduct this amount from future payments due Seller.

TABLE B-3

Forecasted Incremental Energy Rates and Incremental Energy Rate Bounds

Curtailment Option A:

Year	Forecasted Incremental Energy Rates, Btu/kWh (a)	Incremental Energy Rate Band Width from Article 4, Btu/kWh (b)	Upper Incremental Energy Rate Bound, Btu/kWh [column (a) plus column (b)]	Lower Incremental Energy Rate Bound, Btu/kWh [column (a) minus column (b)]
1984	9,000			
1985	9,050			
1986	8,840			
1987	8,850			
1988	8,960			
1989	8,820			
1990	8,540			
1991	8,540			
1992	8,540			
1993	8,540			
1994	8,540			
1995	8,540			
1996	8,540			
1997	8,540			
1998	8,540			

TABLE B-3—(Continued)

Forecasted Incremental Energy Rates and Incremental Energy Rate Bounds

Curtailment Option B:

Year	Forecasted Incremental Energy Rates, Btu/kWh (a)	Incremental Energy Rate Band Width from Article 4, Btu/kWh (b)	Upper Incremental Energy Rate Bound, Btu/kWh [column (a) plus column (b)]	Lower Incremental Energy Rate Bound, Btu/kWh [column (a) minus column (b)]
1984	9,440			
1985	9,500			
1986	9,280			
1987	9,290			
1988	9,400			
1989	9,270			
1990	8,970			
1991	8,970			
1992	8,970			
1993	8,970			
1994	8,970			
1995	8,970			
1996	8,970			
1997	8,970			
1998	8,970			

TABLE B-4[1]

	Monday through Friday[2]	Saturdays[2]	Sundays and Holidays
Seasonal Period A (May 1 through September 30)			
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m. 6:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day
Seasonal Period B (October 1 through April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m. 8:30 a.m. to 4:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day

[1] This table is subject to change to accord with the on-peak, partial-peak, and off-peak periods as defined in PGandE's own rate schedules for the sale of electricity to its large industrial customers.

[2] Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving , and Christmas as said days are specified in Public Law 90-363 (5 U.S.C.A. Section 6103(a).

Table B-5

Energy Prices Effective
August 1-October 31, 1983

The energy purchase price calculations which will apply to energy deliveries determined from meter readings taken during August, September, and October 1983 are as follows:

Time Period	Incremental Heat Rate(1) (a)	Cost of Energy(2) (b)	Energy Purchase Price(3)(4) (c) = (a) × (b)
May 1—September 30 (Period A)			
Time of Delivery Basis:			
On Peak	11,447 Btu/kWh	$5.3948/6 Btu	$0.06175/kWh
Partial-Peak	10,919	5.3948	0.05891
Off-Peak	10,549	5.3948	0.05691
Seasonal Average (Period A)	10,821	5,3948	0.05838
October 1—April 30 (Period B)			
Time of Delivery Basis:			
On-Peak	11,605 Btu/kWh	$5,3948/6 Btu	$0.06261/kWh
Partial-Peak	11.341	5.3948	0.06118
Off-Peak	11,067	5.3948	0.05970
Seasonal Average (Period B)	11,231	5.3948	0.06059

(1) Incremental heat rates are derived from marginal energy costs (including variable operating and maintenance expense) adopted by *CPUC* Decision No. 93887. They are adjusted to reflect the use of natural gas as the incremental fuel.

(2) Cost of natural gas under PGandE Gas Schedule No. G-55 effective 7/1/83 per Advice No. 1225-G (Supplemental), Resolution No. 2545.

(3) Energy Purchase Price = Incremental Heat Rate × Cost of Energy.

(4) This figure excludes the applicable energy line loss adjustment factors. However, as ordered by Ordering Paragraph No. 12(j) of Decision No. 82-12-120, this figure is currently 1.0 for transmission and primary distribution loss adjustments and is equal to marginal cost line loss adjustment factors for the secondary distribution voltage level. These factors may be changed by the *CPUC* in the future.

APPENDIX C

CURTAILMENT OPTIONS

Seller has two options regarding curtailment of energy deliveries and Seller has made its selection in Article 6. The two options are as follows:

CURTAILMENT OPTION A—HYDRO SPILL AND NEGATIVE AVOIDED COST

(a) In anticipation of a period of hydro spill conditions, as defined by the *CPUC*, PGandE may notify Seller that any purchases of energy from Seller during such period shall be at hydro savings prices quoted by PGandE. If Seller delivers energy to PGandE during any such period, Seller shall be paid hydro savings prices for those deliveries in lieu of prices which would otherwise be applicable. The hydro savings prices shall be calculated by PGandE using the following formula:

$$\frac{AQF\text{-}S}{AQF} \times PP \quad (\geq 0)$$

where:

AQF= Energy, in kWh, projected to be available during hydro spill conditions from all qualifying facilities under agreements containing hydro savings price provisions.

S = Potential energy, in kWh, from PGandE hydro facilities which will be spilled if all AQF is delivered to PGandE.

PP = Prices published by PGandE for purchases during other than hydro spill conditions.

PGandE shall give Seller notice of general periods when hydro spill conditions are anticipated, and shall give Seller as much advance notice as practical of any specific hydro spill period and the hydro savings price which will be applicable during such period.

(b) PGandE shall not be obligated to accept or pay for and may require Seller with a *Facility* with a nameplate rating of one megawatt or greater to interrupt or reduce deliveries of energy

during periods when PGandE would incur negative avoided costs (as defined by the *CPUC*) due to continued acceptance of energy deliveries under this Agreement.

Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

(c) Before interrupting or reducing deliveries under subsection (b), above, and before invoking hydro savings prices under subsection (a), above, PGandE shall take reasonable steps to make economy sales of the surplus energy giving rise to the condition. If such economy sales are made, while the surplus energy condition exists Seller shall be paid at the economy sales price obtained by PGandE in lieu of the otherwise applicable prices.

(d) If Seller is selling *net energy output* to PGandE and simultaneously purchasing its electrical needs from PGandE and Seller elects not to sell energy to PGandE at the hydro savings price pursuant to subsection (a) or when PGandE curtails deliveries of energy pursuant to subsection (b), Seller shall not use such energy to meet its electrical needs but shall continue to purchase all its electrical needs from PGandE. If Seller is selling *surplus energy output* to PGandE, subsections (a) or (b) shall only apply to the *surplus energy output* being delivered to PGandE, and Seller can continue to internally use that generation it has retained for its own use.

CURTAILMENT OPTION B—ADJUSTED PRICE PERIOD

(a) In each calendar year, the price which PGandE is obligated to pay Seller for energy deliveries during 1,000 off-peak hours (as defined in Table B-4, Appendix B) may be adjusted to a price equal to, but not in excess of, PGandE's available alternative source. This adjusted price shall be effective under any of the following conditions:

(i) when PGandE's energy source at the margin is not a PGandE oil- or gas-fueled plant, and PGandE can replace Seller's energy with energy from this source at a cost less than the price paid to Seller;

(ii) when PGandE would incur negative avoided costs (as defined by the *CPUC*) due to continued acceptance of energy deliveries under this Agreement; or

(iii) when PGandE is experiencing minimum system operations.

During any of the conditions described above the adjusted price may be zero.

(b) Whenever possible, PGandE shall give Seller reasonable notice of any price adjustment for energy deliveries and its probable duration.

(c) If Seller is selling *net energy output* to PGandE and simultaneously purchasing its electrical needs from PGandE and Seller elects not to sell energy to PGandE at the adjusted price, Seller shall not use such energy to meet its electrical needs but shall continue to purchase all its electrical needs from PGandE.

(d) After Seller receives notice of the probable duration of the period during which the adjusted price will be paid, Seller may elect to perform maintenance during such period and so inform the PGandE employee in charge at the *designated PGandE switching center* prior to the time when the adjusted price period is expected to begin. If Seller makes such election, the number of off-peak hours of probable duration quoted in PGandE's notice to Seller shall be applied to the 1,000 hour calendar year limitation set forth in this section. After an election to do maintenance, if Seller makes any deliveries of energy during the quoted probable duration period, Seller shall be paid the adjusted price quoted in its notice from PGandE without regard to any subsequent changes on the PGandE system which may alter the adjusted price or shorten the actual duration of the condition.

APPENDIX D

AS-DELIVERED-CAPACITY

D-1 AS-DELIVERED CAPACITY PAYMENT OPTIONS

Seller has two options for *as-delivered capacity* payments and Seller has made its selection in Article 5. The two options are as follows:

AS-DELIVERED CAPACITY PAYMENT OPTION 1

PGandE shall pay Seller for *as-delivered capacity* at prices authorized from time to time by the *CPUC*. The *as-delivered capacity* prices in effect on the date of execution are calculated as shown in Exhibit D-1, with a shortage cost of $70 per kilowatt-year.

AS-DELIVERED CAPACITY PAYMENT OPTION 2

During the *fixed price period,* the *as-delivered capacity* prices will be calculated in accordance with Exhibit D-1 and the forecasted shortage costs in Table D-2.

For the remaining years of the *term of agreement,* PGandE shall pay Seller for *as-delivered capacity* at the higher of:

(i) Prices authorized from time to time by the *CPUC;*

(ii) the *as-delivered capacity* prices that were paid Seller in the last year of the *fixed price period;* or

(iii) the *as-delivered capacity* prices in effect in the first year following the end of the *fixed price period,* provided that the annualized shortage cost from which these prices are derived does not exceed the annualized value of a gas turbine.

D-2 AS-DELIVERED CAPACITY IN EXCESS OF FIRM CAPACITY

The amount of capacity delivered in excess of *firm capacity* will be considered *as-delivered capacity*. This *as-delivered capacity* is

based on the total kilowatt-hours delivered each month during all on-peak, partial-peak and off-peak hours excluding any energy associated with generation levels equal to or less than the *firm capacity*.

Seller has the two options listed in Section D-1 for payment for such *as-delivered capacity*. Seller has made its selection in Article 5.

EXHIBIT D-1

The *as-delivered capacity* price (in cents per kW-hr) for power delivered by the *Facility* is the product of three factors:

(a) The shortage cost in each year the *Facility* is operating.

(b) A capacity loss adjustment factor which provides for the effect of the deliveries on PGandE's transmission and distribution losses based on the Seller's interconnection voltage level. The applicable capacity loss adjustment factors for non-remote[1] Facilities are presented in Table D-1(a). Capacity loss adjustment factors for remote Facilities shall be calculated individually.

(c) An allocation factor which accounts for the different values of *as-delivered capacity* in different time periods and converts dollars per kW-year to cents per kWh. The current allocation factors are presented in Table D-1(b). The time periods to which they apply are shown in Table B-4, Appendix B. The allocation factors are subject to change from time to time.

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[1] As defined by the *CPUC*.

TABLE D-1(a)
Capacity Loss Adjustment Factors For Non-Remote(1) Facilities

Voltage Level	Loss Adjustment Factor
Transmission	.989
Distribution	.991

If the *Facility* is remote, the capacity loss adjustment factor is _____.(2)

TABLE D-1(b)
Allocation Factors For As-Delivered Capacity(3)

	Peak (¢-yr/$-hr)	Partial Peak (¢-yr/$-hr)	Off-Peak (¢-yr/$-hr)
Seasonal Period A	.09982	.01635	.00000
Seasonal Period B	.02023	.00306	.00001

TABLE D-2
Forecasted Shortage Cost Schedule

Year	Forecast Shortage Cost, $/kW-Yr
1983	70
1984	76
1985	81
1986	88
1987	95
1988	102
1989	110
1990	118
1991	126
1992	135
1993	144
1994	154
1995	164
1996	176
1997	188

(1) As defined by the *CPUC*. The capacity loss adjustment factors for remote Facilities are determined individually.

(2) Determined individually.

(3) The units for the allocation factor, ¢-yr/$-hr, are derived from the conversion of $/kW-yr into ¢/kWh as follows:

$$\frac{¢/kWh}{\$/kW\text{-}yr} = \frac{¢/kW\text{-}hr}{\$/kW\text{-}yr} = \frac{¢\text{-}yr}{\$\text{-}hr}$$

The allocation factors are subject to change from time to time.

APPENDIX E
FIRM CAPACITY

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APPENDIX E

FIRM CAPACITY

E-1 GENERAL

This Appendix E estabished conditions and prices under which PG&E shall pay for *firm capacity*.

PG&E's obligation to pay for *firm capacity* shall begin on the *firm capacity availability date*. The *firm capacity price* shall be subject to adjustment as provided for in this Appendix E.

The *firm capacity prices* in Table E-2 are applicable for deliveries of *firm capacity* beginning after December 30, 1982.

E-2 MINIMUM PERFORMANCE REQUIREMENTS

(a) To receive full capacity payments, the *firm capacity* shall be delivered for all of the on-peak hours[1] in the peak months on the PGandE system, which are presently the months of June, July, and August, subject to a 20 percent allowance for *forced outages* in any month. Compliance with this provision shall be based on the *Facility's* total on-peak deliveries for each of the peak months and shall exclude any energy associated with generation levels greater than the *firm capacity*.

(b) If Seller is prevented from meeting the minimum performance requirements because of a forced outage on the PGandE system, a PGandE curtailment of Seller's deliveries, or a condition set forth in Section A-7, Appendix A, PGandE shall continue capacity payments. *Firm capacity* payments will be calculated in the same manner used for scheduled maintenance outages.

(c) If Seller is prevented from meeting the minimum performance requirements because of force majeure, PGandE shall continue capacity payments for ninety days from the occurrence of the force majeure. Thereaf-

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[1] On-peak, partial-peak, and off-peak hours are defined in Table B-4, Appendix B.

ter, Seller shall be deemed to have failed to have met the minimum performance requirements. *Firm capacity* payments will be calculated in the same manner used for scheduled maintenance outages.

(d) If Seller is prevented from meeting the minimum performance requirements because of extreme dry year conditions, PGandE shall continue capacity payments. Extreme dry year conditions are drier than those used to establish *firm capacity* pursuant to Section E-8. Seller shall warrant to PGandE that the *Facililty* is a hydroelectric facility and that such conditions are the sole cause of Seller's inability to meet its *firm capacity* obligations.

(e) If Seller is prevented from meeting the minimum preformance requirements for reasons other than those described above in Sections E-2(b), (c), or (d):

(1) Seller shall receive the reduced *firm capacity* payments as provided in Section E-5 for a probationary period not to exceed 15 months, or as otherwise agreed to by the Parties.

(2) If, at the end of the probationary period Seller has not demonstrated that the *Facility* can meet the minimum performance requirements, PGandE may derate the *firm capacity* pursuant to Section E-4(b).

E-3 SCHEDULED MAINTENANCE

Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. Seller may accumulate unused maintenance hours from one 12-month period to another up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. Seller shall provide PGandE with the following advance notices: 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major overhauls), and six

months for a major overhaul. Seller shall not schedule major overhauls during the peak months (presently June, July and August). Seller shall make reasonable efforts to schedule or reschedule routine maintenance outside the peak months, and in no event shall outages for scheduled maintenance exceed 30 peak hours during the peak months. Seller shall confirm in writing to PGandE pursuant to Article 9, within 24 hours of the original notice, all notices Seller gives personally or by telephone for scheduled maintenance.

If Seller has selected Curtailment Option B, off-peak hours of maintenance performed pursuant to Section (d) of Curtailment Option B, Appendix C shall not be deducted from Seller's scheduled maintenance allowances set forth above.

E-4 Adjustments to Firm Capacity

(a) Seller may increase the *firm capacity* with the approval of PGandE and receive payment for the additional capacity thereafter in accordance with the applicable capacity purchase price published by PGandE at the time the increase is first delivered to PGandE.

(b) Seller may reduce the *firm capacity* at any time prior to the *firm capacity availability date* by giving written notice thereof to PGandE. PGandE may derate the *firm capacity* as a result of appropriate tests, studies, or prior performance.

E-5 Firm Capacity Payments

The method for calculation of *firm capacity* payments is shown below. As used below in this section, month refers to a calendar month.

The monthly payment for *firm capacity* will be the product of the Period Price Factor (PPF), the Monthly Delivered Capacity (MDC), the appropriate capacity loss adjustment factor from Table E-1 based on the *Facility's* interconnection voltage, and the appropriate performance bonus factor, if any, from Table E-3, plus any allowable payment for outages due to scheduled maintenance. The *firm capacity price* shall be applied to meter readings

taken during the separate times and periods as illustrated in Table B-4, Appendix B.

The PPF is determined by multiplying the *firm capacity price* by the following Allocation Factors:[1]

	Allocation Factor	×	Firm Capacity Price	=	PPF ($/kW-month)
Seasonal Period A.....	.16479		_____		_____
Seasonal Period B.....	.02515		_____		_____

The MDC is determined in the following manner:

(1) Determine the Performance Factor (P), which is defined as the lesser of 1.0 or the following quantity:

$$P = \frac{A}{C \times (B\text{-}S) \times (0.8^*)} (\leq 1.0)$$

*0.8 reflects a 20% allowance for *forced outage.*

Where:

A = Total kilowatt-hours delivered during all on-peak and partial-peak hours excluding any energy associated with generation levels greater than the *firm capacity.*

C = *Firm capacity* in kilowatts.

B = Total on-peak and partial-peak hours during the month.

S = Total on-peak and partial-peak hours during the month *Facility* is out of service on scheduled maintenance.

(2) Determine the Monthly Capacity Factor (MCF), which is computed using the following expression:

[1] All allocation factors are subject to change by PGandE based on PGandE's marginal capacity cost allocation, as determined in general rate case proceedings before the *CPUC.* Seasonal Periods A and B are defined in Table B-4, Appendix B.

$$MCF = P \times (1.0 - \frac{M}{D})$$

Where:

M = The number of hours during the month *Facility* is out of service on scheduled maintenance.

D = The number of hours in the month.

(3) Determine the MDC by multiplying the MCF by C:

$$MDC \quad (\text{kilowatts}) = MCF \times C$$

The monthly payment for *firm capacity* is then determined by multiplying the PPF by the MDC, by the appropriate capacity loss adjustment factor presented from Table E-1, and by the appropriate performance bonus factor, if any, from Table E-3.

$$\text{monthly payment for } \textit{firm capacity} = PPF \times MDC \times \text{capacity loss adjustment factor} \times \text{performance bonus factor}$$

Furthermore, the payment for a month in which there is an outage for scheduled maintenance shall also include an amount equal to the product of the average hourly *firm capacity* payment[1] for the most recent month in the same type of Seasonal Period (i.e., Seasonal Period A or Seasonal Period B) during which deliveries were made times the number of hours of outage for scheduled maintenance in the current month. *Firm capacity* payments will continue during the outage periods for scheduled maintenance provided that the provisions of Section E-3 are met.

During a probationary period Seller's monthly payment for *firm capacity* shall be determined by substituting for the *firm capacity*, the capacity at which Seller would have met the minimum performance requirements. In the event that during the probationary period Seller does not meet the minimum performance requirements at whatever *firm capacity* was established for the previous month, Seller's monthly payment for *firm capacity* shall be determined by substituting the *firm capacity* at which Seller

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[1] Total monthly payment divided by the total number of hours in the monthly billing period.

would have met the minimum performance requirements. The performance bonus factor shall not be applied during probationary periods.

TABLE E-1

If the *Facility* is non-remote[2] the *firm capacity* loss adjustment factors are as follows:

Interconnection Voltage	Capacity Loss Adjustment Factor
Transmission	.989
Distribution	.991

If the *Facility* is remote the *firm capacity* loss adjustment factor is _____[3]

[2] As defined by the *CPUC*.

[3] Determined individually.

TABLE E-2

Firm Capacity Price Schedule
(Levelized $/kW-year)

Firm Capacity Availability Date	Number of Years of *Firm Capacity Delivery*																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
(Year)																		
1982 ...	65	68	70	72	75	77	79	81	84	86	88	90	91	93	95	103	109	113
1983 ...	70	73	75	78	80	83	85	88	90	92	94	96	98	100	102	110	117	122
1984 ...	76	78	81	84	86	89	92	94	97	99	101	103	106	108	110	118	125	130
1985 ...	81	84	87	90	93	96	99	101	104	106	109	111	113	115	118	127	134	140
1986 ...	88	91	94	97	100	103	106	109	112	114	117	119	122	124	126	136	144	150
1987 ...	95	98	101	105	108	111	114	117	120	123	125	128	130	133	135	146	154	160

TABLE E-3

Performance Bonus Factor

The following shall be the performance bonus factors applicable to the calculation of the monthly payments for *firm capacity* delivered by the *Facility* after it has demonstrated a *firm capacity* factor in excess of 85%.

DEMONSTRATED FIRM CAPACITY FACTOR (%)	PERFORMANCE BONUS FACTOR
85	1.000
90	1.059
95	1.118
100	1.176

After the *Facility* has delivered power during the span of all of the peak months on the PGandE system (presently June, July, and August) in any year (span),

(i) the *firm capacity* factor for each such month shall be calculated in the following manner:

$$\text{FIRM CAPACITY FACTOR (\%)} = \frac{A}{B \times C} \times 100$$

Where:

A = Total kilowatt-hours delivered by Seller in any peak month during all on-peak hours excluding any energy associated with generation levels greater than the *firm capacity*.

B = Total on-peak hours during the month.

C = *Firm capacity* in kilowatts.

(ii) the arithmetic average of the above *firm capacity* factors shall be determined for that span,

(iii) the average of the above arithmetic average *firm capacity* factors for the most recent span(s), not to exceed 5, shall be calculated and shall become the Demonstrated Firm Capacity Factor.

To calculate the performance bonus factor for a Demonstrated Firm Capacity Factor not shown in Table E-3 use the following formula:

$$\text{Performance Bonus Factor} = \frac{\text{Demonstrated Firm Capacity Factor (\%)}}{85\%}$$

SECTIONS E-6 THROUGH E-10 SHALL APPLY ONLY TO HYDROELECTRIC PROJECTS

E-6 DETERMINATION OF NATURAL FLOW DATA

Natural flow data shall be based on a period of record of at least 50 years and which includes historic critically dry periods. In the event Seller demonstrates that a natural flow data base of at least 50 years would be unreasonably burdensome, PGandE shall accept a shorter period of record with a corresponding reduction in the averaging basis set forth in Section E-8. Seller shall determine the natural flow data by month by using one of the following methods:

Method 1

If stream flow records are available from a recognized gauging station on the water course being developed in the general vicinity of the project, Seller may use the data from them directly.

Method 2

If directly applicable flow records are not available, Seller may develop theoretical natural flows based on correlation with available flow data for the closest adjacent and similar area which has a recognized gauging station using generally accepted hydrologic estimating methods.

E-7 THEORETICAL OPERATION STUDY

Based on the monthly natural flow data developed under Section E-6 a theoretical operation study shall be prepared by Seller. Such a study shall identify the monthly capacity rating in kW and the monthly energy production in kWh for each month of

each year. The study shall take into account all relevant operating constraints, limitations, and requirements including but not limited to —

(1) Release requirements for support of fish life and any other operating constraints imposed on the project;

(2) Operating characteristics of the proposed equipment of the *Facility* such as efficiencies, minimum and maximum operating levels, project control procedures, etc.;

(3) The design characteristics of project facilities such as head losses in penstocks, valves, tailwater elevation levels, etc., and

(4) Release requirements for purposes other than power generation such as irrigation, domestic water supply, etc.

The theoretical operation study for each month shall assume an even distribution of generation throughout the month unless Seller can demonstrate that the *Facility* has water storage characteristics. For the study to show monthly capacity ratings, the *Facility* shall be capable of operating during all on-peak hours in the peak months on the PGandE system, which are presently the months of June, July, and August. If the project does not have this capability throughout each such month, the capacity rating in that month of that year shall be set at zero for purposes of this theoretical operation study.

E-8 DETERMINATION OF AVERAGE DRY YEAR CAPACITY RATINGS

Based on the results of the theoretical operation study developed under Section E-7, the average dry year capacity rating shall be established for each month. The average dry year shall be based on the average of the five years of the lowest annual generation as shown in the theoretical operation study. Once such years of lowest annual generation are identified, the monthly capacity rating is determined for each month by averaging the capacity ratings from each month of those years. The *firm capacity* shown in Article 5 shall not exceed the lowest average

dry year monthly capacity ratings for the peak months on the PGandE system, which are presently the months of June, July, and August.

E-9 INFORMATION REQUIREMENTS

Seller shall provide the following information to PGandE for its review:

(1) A summary of the average dry year capacity ratings based on the theoretical operation study as provided in Table E-4;

(2) A topographic project map which shows the location of all aspects of the *Facility* and locations of stream gauging stations used to determine natural flow data;

(3) A discussion of all major factors relevant to project operation;

(4) A discussion of the methods and procedures used to establish the natural flow data. This discussion shall be in sufficient detail for PGandE to determine that the methods are consistent with those outlined in Section E-6 and are consistent with generally accepted engineering practices; and

(5) Upon specific written request by PGandE, Seller's theoretical operation study.

E-10 ILLUSTRATIVE EXAMPLE

(1) Determine natural flows—These flows are developed based on historic stream gauging records and are compiled by month, for a long-term period (normally at least 50 years or more) which covers dry periods which historically occurred in the 1920's and 30's and more recently in 1976 and 77. In all but unusual situations this will require application of hydrological engineering methods to records that are available, primarily from the USGS publication "Water Resources Data for California".

(2) Perform theoretical operation study—Using the natural flow data compiled under (1) above a theoretical operation study is prepared which determines, for each month of each year, energy generation (kWh) and capacity rating (kW). This

study is performed based on the *Facility's* design, operating capabilities, constraints, etc., and should take into account all factors relevant to project operation. Generally such a study is done by computer which routes the natural flows through project features, considering additions and withdrawals from storage, spill past the project, releases for support of fish life, etc., to determine flow available for generation. Then the generation and capacity amounts are computed based on equipment performance, efficiencies, etc.

(3) Determine average dry year capacity ratings—After the theoretical project operation study is complete the five years in which the annual generation (kWh) would have been the lowest are identified. Then for each month, the capacity rating (kW) is averaged for the five years to arrive at a monthly average capacity rating. The *firm capacity* is then set by the Seller based on the monthly average dry year capacity ratings and the minimum performance requirements of this appendix. An example project is shown in the attached completed Table E-4.

EXAMPLE

TABLE E-4

Summary of Theoretical Operation Study

Project: New Creek 1

Water Source: West Fork New Creek

Mode of Operation: Run of the river

Type of Turbine: Francis

Design Flow: 100 cfs Design Head: 150 feet

Operating Characteristics: [1]

	Flow (cfs)	Head (feet)		Output (kW)	Efficiency (%)	
		Gross	Net		Turbine	Generator
Normal Operation ...	100	160	150	1,120	90	98
Maximum Operation	110	160	148	1,150	85	98
Minimum Operation	30	160	155	290	75	98

Average Dry Year Operation—Based on the average of the following lowest generation years: 1930, 1932, 1934, 1949, 1977.

Month	Energy Generation (kWh)	Capacity Output (kW)	Percent of Total Hours Operated
January	855,000	1,150	100
February	753,000	1,120	100
March	818,000	1,100	100
April	727,000	1,010	100
May	699,000	940	100
June	612,000	850	100
July	484,000	650	100
August	305,000	410	100
September	245,000	340	100
October	148,800	200	100
November	468,000	650	100
December	595,000	800	100

Maximum *firm capacity*: 410 kW

[1] If *Facility* has a variable head, operating curves should be provided.

E-11 MINIMUM DAMAGES

(a) In the event the *firm capacity* is derated or Seller terminates this Agreement, the quantity by which the *firm capacity* is derated or the *firm capacity* shall be used to calculate the payments due PGandE in accordance with Section (d).

(b) Seller shall be invoiced by PGandE for all amounts due under this section. Payment shall be due within 30 days of the date of the invoice.

(c) If Seller does not make payments pursuant to Section (b), PGandE shall have the right to offset any amounts due it against any present or future payments due Seller.

(d) Seller shall pay to PGandE:

(i) an amount equal to the difference between (a) the *firm capacity* payments already paid by PGandE, based on the original *term of agreement* and (b) the total *firm capacity* payments which PGandE would have paid based on the period of Seller's actual performance using the *adjusted firm capacity price.* Additionally, Seller shall pay interest, compounded monthly from the date the excess capacity payment was made until the date Seller repays PGandE, on all overpayments, at the published Federal Reserve Board three months' Prime Commercial Paper rate; plus

(ii) a sum equal to the amount by which the *firm capacity* is being terminated or derated times the difference between the *current firm capacity price* on the date of termination or deration for a term equal to the balance of the *term of agreement* and the *firm capacity price*, multiplied by the appropriate factor shown in Table E-5 below. In the event that the *current firm capacity price* is less than the *firm capacity price*, no payment under this subsection (ii) shall be due either party.

TABLE E-5

Amount of *Firm Capacity* Terminated or Derated	Factor
1,000 kW or under	0.25
over 1,000 kW through 10,000 kW	0.75
over 10,000 through 25,000 kW	1.00
over 25,000 kW through 50,000 kW	3.00
over 50,000 kW through 100,000 kW	4.00
over 100,000 kW	5.00

APPENDIX L

Decision 87-01-049 January 28, 1987

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application 82-04-44 (Filed April 21, 1982; amended April 28, 1982, July 19, 1982, July 11, 1983, August 2, 1983)

Application 82-04-46 (Filed April 21, 1982; amended May 12, 1982, July 11, 1983, August 10, 1983, October 27, 1983, January 4, 1984, May 4, 1984, June 20, 1984, and August 20, 1986)

Application 82-04-47 (Filed April 21, 1982; amended July 11, 1982, August 2, 1983, September 6, 1984, and August 20, 1986)

Application 82-03-26 (Filed March 8, 1982)

Application 82-03-37 (Filed March 8, 1982)

Application 82-03-62 (Filed March 16, 1982)

Application 82-03-67 (Filed March 18, 1982)

Application 82-03-78 (Filed March 22, 1982)

Application 82-04-21 (Filed April 8, 1982)

Second application of Pacific Gas and Electric Company for approval of certain standard offers pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2.

And Related Matters.

OPINION

In its petition for modification of Decision (D.)83-09-054 filed October 29, 1986, Independent Energy Producers Association (IEP) requests that the Commission permit "pioneer" qualifying facility (QF) projects the opportunity to switch to interim Stan-

dard Offer 4. IEP defines "pioneer" projects as QFs now generating under contracts signed prior to September 9, 1983.[1]

IEP's petition emphasizes that the Commission sought to elicit early QF development by providing QFs the option to switch to the final standard offers when they were completed. D.93054[sic], for example, explicitly ordered that language be inserted into early QF contracts permitting conversion of those contracts to the final standard offers. Even after the adoption of the short-run standard offers, many QF contracts included negotiated clauses that guaranteed the QF the right to switch to the final long-run standard offer. Moreover, IEP asserts, still other QFs signed firm contracts only because they believed they would be able to receive the final long-run offer prices once that offer was adopted by the Commission.

IEP notes that the development of a final long-run offer has taken much longer than either the QFs or the Commission anticipated. In fact, delays in adopting a final long-run offer and the desire to stimulate more rapid QF development were primary considerations in the Commission's decision to approve a negotiated interim Standard Offer 4 contract. Because the Commission still hoped to adopt a final long-run offer based on a record developed through evidentiary hearings, the Commission declined to allow QFs already under contract the option to switch to interim Standard Offer 4 (D.83-09-054).

IEP argues that the longer-than-anticipated lapse between the adoption of interim Standard Offer 4 and the adoption of a final long-run offer should lead the Commission to reconsider its ban on contract switching. In IEP's view, the pioneers have been unfairly disadvantaged by the substantial amount of capacity

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[1] Although IEP defines pioneers as those QFs that signed contracts prior to September 9, 1983, it is clear from IEP's petition that it intends to include only those QFs that are now generating under contracts signed prior to the adoption of interim Standard Offer 4. Interim Standard Offer 4 was actually adopted by this Commission on September 7, 1983. All subsequent references to pioneer QFs in this decision shall be construed to mean those QFs now generating under contracts signed prior to September 7, 1983.

coming on line under interim Standard Offer 4. This later QF capacity has the effect of depressing energy prices paid to pioneer QFs at a time when the precipitous drop in oil and gas prices already has caused their energy payments to plummet. According to IEP, many pioneer QFs now receive payments insufficient to meet their debt service obligations. This dramatic decrease in energy payments, IEP believes, could not have been foreseen by a prudent manager at the time these early contracts were signed.

The result of this drop in energy payments may well be to force many pioneer QFs to cease generation or to go out of business entirely. IEP believes that such an outcome is not in the best interest of California's ratepayers or the California economy as a whole. Therefore, IEP requests that the Commission grant the pioneers the option to switch to interim Standard Offer 4 or some variation thereof.

Responses to IEP's Petition

PGandE. PGandE opposes IEP's petition on the grounds that pioneers have no equitable or legal entitlement to switch to interim Standard Offer 4. PGandE emphasizes the importance of balancing the needs of pioneer QFs against the cost to PGandE ratepayers of wholesale extension of interim Standard Offer 4. Although PGandE acknowledges that certain pioneer QFs are experiencing economic hardship, it notes that some pioneers are already operating at a profit. To extend interim Standard Offer 4 terms to these QFs would, in PGandE's view, give them an unwarranted windfall at the ratepayers' expense.

PGandE has already begun negotiating with individual pioneer QFs to restructure their contracts in a way that enables the pioneers to remain in business while providing ratepayer benefits equal or greater to those in the existing contracts. PGandE recommends that the Commission allow pioneer sellers the opportunity to renegotiate their existing contracts before considering across-the-board remedies. Furthermore, PGandE believes that the Commission lacks legal authority to extend interim Standard Offer 4 to pioneer QFs.

PGandE cites seven distinctions among pioneer QFs as evidence in favor of a case-by-case approach. According to PGandE, pioneers differ widely in (1) their financial situations, (2) the nature of their economic problems (unforeseeable vs. self-induced), (3) the use to which they intend to put the additional funds if received, (4) whether a transfer of ownership has occurred since D. 83-09-054, (5) whether the facility burns oil or gas, (6) whether the pioneer seller also holds "gold rush" interim Standard Offer 4 contracts, and (7) whether the seller holds a nonstandard agreement in which PGandE or its ratepayers assumed financial risk or made other arrangements for project financing. Each of these distinctions, in PGandE's view, affects the merit of a pioneer QF's claim for equitable relief from the prohibition on contract switching.

PGandE observes that some pioneer QFs could have switched to interim Standard Offer 4 prior to that offer's suspension. Allowing these QFs an opportunity to reconsider their decision not to switch in light of a hindsight review of the costs and benefits of doing so is unfair, argues PGandE.

Edison. Edison also opposes IEP's petition. Central to its argument are two premises. First, at the time they entered into their contracts, pioneer QFs knowlingly accepted certain risks with respect to future Commission-developed contracts and prices. Second, permitting pioneer QFs to switch to interim Standard Offer 4 would be prohibitively costly to Edison's ratepayers. As further support of its position, Edison notes the potential for any relief granted to be contrary to the final report and recommendation of the Commission to the legislature under SB 2674, which requires the Commission to submit no later than May 1, 1987, a report on the problems of pioneer QFs and potential remedies. Edison also cites several Commission orders that it believes provide a clear precedent for maintaining the ban on contract switching.

In the event the Commission decides to grant relief to pioneer QFs, Edison urges that such relief be provided on a case-by-case basis through either negotiated settlement or individual QF petitions for modification of D.83-09-054. In addition, Edison would

limit any relief to those QFs with clauses in their contracts allowing them to switch to the final long-run offer.

SDG&E. SDG&E echoes the position of the other two utilities that permitting pioneer QFs to switch to interim Standard Offer 4 would simply be too costly to its ratepayers. Furthermore, SDG&E believes that the financial risk undertaken by pioneer QFs was clearly understood at that time and was not predicated on an assumption of the right to switch to interim Standard Offer 4. Moreover, SDG&E is not convinced of the claims by IEP that pioneer QFs as a class have been severely impacted by the downturn in avoided cost. Finally, SDG&E cites numerous legal and contractural barriers to allowing pioneer QFs the opportunity to switch to interim Standard Offer 4. If the Comission wishes for equitable reasons to extend the benefits of interim Standard Offer 4 prices to pioneer QFs, SDG&E recommends that the prices received by QFs coming on line after the pioneers be reduced by a comparable amount to ensure that ratepayers receive the benefits to which they are entitled.

Discussion

The fundamental question before the Commission is one of timing. Pioneer QFs (i.e., those that signed contracts prior to the adoption of interim Standard Offer 4) provided the ratepayers with a valuable service at a time when the ability of the utilities' own central-station generation facilities to serve the growing demand for electricity was in question. These pioneers faced substantial risks by coming on line prior to the availability of a long-run standard offer that would fully recognize their contribution to the reliability of the utilities' systems. Moreover, while the electrical capacity currently available to California is ample, there is every reason to expect that the output from pioneer QFs will again be greatly needed well within the economic life of their power plants. The question, then, is whether pioneer QFs are to fall or survive solely on the basis of their relatively low short-term benefits to the system or whether we should recognize now, through increased price stability, their undoubtedly greater value considering economic lives of 20 to 30 years or more.

PGandE argues that the decision to take such a risk (i.e., that short-term prices would drop drastically) is a normal element of doing business and that the entire premise of PURPA is to rely on market forces rather than cost-of-service ratemaking. We agree with this general characterization of the QF program; however, the unique circumstances surrounding the pioneer QF problem are sufficient to warrant special consideration.

Given the conditions under which this Commission initiated the QF program, we find IEP's assertions regarding the expectations of pioneer QFs plausible. Many pioneers made the decision to enter into early contracts only because they believed this Commission implicitly or explicitly assured them of the right to convert to a final long-run offer once such an offer was adopted. Such expectations were a reasonable reading of the Commission's orders and statements regarding the QF program; it has always been the Commission's intention that those who answered the call when QF energy was most urgently needed would be appropriately compensated for the risks they undertook.

Unfortunately, the regulatory process has not moved as rapidly as we had hoped. Developing a market-based approach to resource planning has been a rewarding but time-consuming endeavor. Today, more than three years after the adoption of interim Standard Offer 4, we are still at least several months away from adopting a final long-run standard offer. We do not believe that this Commission or the QFs signing early contracts ever anticipated delays of this magnitude. Certainly, we did not expect such delays when we precluded pioneer QFs from switching to interim Standard Offer 4 in D.83-09-054.

Another unintended result of the lengthy process of developing a final long-run offer is that the magnitude of QF development under the interim offer has substantially reduced the need for, and therefore the value of, QF capacity under a final long-run offer. It is unlikely that any offer will be available in the near future that provides a fair measure of the value of the capacity that pioneer QFs brought to the utilities' systems.

These delays and the attendant reduction in the value of QF capacity to the utilities' systems have significantly reduced the

value and meaning of the option to switch to a final long-run offer. Therefore, we concur with IEP that it is appropriate at this time to reconsider our ban in D.83-09-054 on contract switching.

These delays and the attendant reduction in the value of QF capacity to the utilities' systems have significantly reduced the value and meaning of the option to switch to a final long-run offer. Therefore, we concur with IEP that it is appropriate at this time to reconsider our ban in D.83-09-054 on contract switching.

We cannot, however, ignore the real cost to ratepayers of permitting the pioneers to be paid interim Standard Offer 4 prices. Our decision to suspend the availability of interim Standard Offer 4 (D.85-04-075) reflected our awareness that, considering the number of QFs signing up, the prices in that offer overvalued the energy and capacity value of QF power. Since our supension order, additional QF development under Standard Offer 2 and the drop in oil and gas prices has further reduced the value to ratepayers of additional energy and capacity. The potential for significant overpayments is, in our view, sufficient reason to deny IEP's request that pioneers be allowed to switch to interim Standard Offer 4 contracts.

Balancing the claims of pioneer QFs against the potential for overpayments is difficult. None of the parties in this matter have offered us a viable middle ground. At this time, the suggestion of PGandE and Edison to attempt negotiated settlements with pioneer QFs appears to have the greatest potential for preserving the benefit of the pioneers' contribution to the reliability of the utility systems without unduly burdening ratepayers with increased payment exposure. We note that PGandE has already entered into negotiations with several pioneer QFs and wish to give those negotiations an opportunity to bear fruit before we consider any other solution to the problems of pioneer QFs.

Our decision to postpone further Commission action to allow time for negotiation does not indicate a lack of concern for the problems of pioneer QFs. Indeed, the potential of negotiated settlements to tailor relief more appropriately to the needs of specific projects is one of the reasons we prefer seeking negotiated agreements. We are also concerned, however, that relief be

provided in a timely manner. As the utilities noted in their responses to IEP's petition, this Commission must report to the legislature by May 1, 1987, regarding the pioneer QF problem and possible solutions. To ensure that any negotiations mesh well with [sic] this timetable, we will require the utilities to report to us by March 1, 1987, on the extent of the pioneer QF problem in their service territories and the progress they have achieved in negotiating settlements with pioneer QFs.[2] If those reports suggest that negotiations are unlikely to achieve a balanced solution to the pioneer QF problem, we will reconsider the merits of an across-the-board solution.

Findings of Fact

1. Many pioneer QF contracts contain explicit provisions allowing the QF to convert to the final long-run offer once such an offer is adopted by this Commission.

2. The adoption of a final long-run offer has been delayed significantly in comparison with the expectations of the Commission, QFs and the utilities at the time interim Standard Offer 4 was adopted.

3. The substantial amount of QF capacity signed under interim Standard Offer 4 contracts has significantly reduced the value of additional QF capacity and the likelihood that the Commission will make a final long-run offer available in the near future.

4. In D.85-04-075, the Commission suspended interim Standard Offer 4 because, given then-current expectations, the capacity payments and fixed, forecasted energy payments in that offer overstated the value to ratepayers of QF power.

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[2] The relief that we seek to provide to pioneer QFs is limited to redressing the unintended effects of our ban on contract switching in D.83-09-054. Therefore, we do not believe that relief should be provided to any QF that had the opportunity to switch to interim Standard Offer 4 during the period when that offer was available. We expect the utilities to negotiate accordingly.

5. Without some form of relief from the current low short-term avoided cost payments, many pioneer QFs may cease generation or go out of business entirely.

6. Negotitated contracts offer an oportunity to tailor relief appropriately to the individual needs of specific pioneer QF projects.

Conclusions of Law

1. Unanticipated delays in the adoption of a final long-run offer justify reconsideration of the Commission's decision in D.83-09-054 to prohibit pioneer QFs from switching to interim Standard Offer 4.

2. The potential for substantial overpayments under interim Standard Offer 4 pricing terms is sufficient reason to deny IEP's request that pioneers be allowed to switch to interim Standard Offer 4 pricing terms.

3. Pioneer QFs should receive some degree of insulation from the effects of subsequent QF development on their energy prices.

4. Those pioneer QFs that had an opportunity to insulate themselves from the effects of subsequent QF development on their energy prices by switching to interim Standard Offer 4 should not be protected from the consequences of their business judgment by gaining a second opportunity to obtain some degree of pricing certainty. Therefore, QFs that had the opportunity to switch to interim Standard Offer 4 should be precluded from any relief from the terms of their existing contracts.

ORDER

IT IS ORDERED that PGandE, Edison, and SDG&E shall file with the Commission's Docket Office an original and 12 copies, by March 1, 1987, of a report detailing the extent of pioneer QF development in their respective service territories and the progress achieved in negotiating agreements with individual pioneer QFs.

This order is effective today.

Dated January 28, 1987, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
Commissioners

APPENDIX M

§ 824a-3. Cogeneration and small power production

(a) Cogeneration and small power production rules

Not later than 1 year after November 9, 1978, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to—

(1) sell electric energy to qualifying congeneration facilities and qualifying small power production facilities[1] and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase—

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[1] So in original. Probably should be followed by a comma.

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public inteest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) Rates for sales by utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale—

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) "Incremental cost of alternative electric energy" defined

For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) Exemptions

(1) Not later than 1 year after November 9, 1978, and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power

production facilities are exempted in whole or part from the Federal Power Act [16 U.S.C. 791a et seq.], from the Public Utility Holding Company Act [15 U.S.C. 79, et seq.], from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragrpah (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act [15 U.S.C. 79 et seq.] and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from—

(A) any State law or regulation in effect in a State pursuant to subsection (f) of this section,

(B) the provisions of section 210, 211, or 212 of the Federal Power Act [16 U.S.C. 824i, 824j, or 824k] or the necessary authorities for enforcement of any such provision under the Federal Power Act [16 U.S.C 791a et seq.], or

(C) any license or permit requirement under part I of the Federal Power Act [16 U.S.C. 791a et seq.] any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities

(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utitily for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) Judicial review and enforcement

(1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) of this section in the same manner, and under the same requirements, as judicial review may be obtained under section 2633 of this title in the case of a proceeding to which section 2633 of this title applies.

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f) of this section. Any such action shall be brought only in the manner, and under the requirements, as provided under section 2633 of this title with respect to an action to which section 2633 of this title applies.

(h) Commission enforcement

(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) of this section with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act [16 U.S.C. 824 et. seq.], such rule shall be

treated as a rule under the Federal Power Act [16 U.S.C. 791a et seq.]. Nothing in subsection (g) of this section shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act.

(2)(A) The Commission may enforce the requirements of subsection (f) of this section against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) of this section shall be treated as a rule enforceable under the Federal Power Act [16 U.S.C. 791a et seq.]. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than—

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f) of this section[2] or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) of this section as provided in subparagraph (A) of this paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

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[2] So in original. Probably should be followed by a comma.

(i) Federal contracts

No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after November 9, 1978, may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) Definitions

For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act [16 U.S.C. 796(17), (18)].

(Pub. L. (95-617, title II, § 210, Nov. 9, 1978, 92 Stat. 3144; Pub. L. 96-294, title VI, § 643(b), June 30, 1980, 94 Stat. 770.)

APPENDIX N

Finance Insurance and Commerce Committee
Alister McAlister, Chairman

Assembly Bills 1402 and 1403—Hayes—As introduced

Fiscal Committee: Yes

Hearing Date: January 16, 1980

Background

At the present time, a small number of private companies are able to generate electricity as a by-product of their manufacturing processes through what is known as cogeneration. Cogeneration is the generation of electricity from the exhaust steam, waste steam or heat created by an industrial, commercial or manufacturing plant in the manufacturing process.

Companies which are able to generate electricity by using cogeneration technology consume that electricity for their own operations. However, when they do not need the electricity they have generated, they sell it to electric utilities which serve the public, such as PG&E.

Analysis

AB 1402 and AB 1403 encourage the development of electricity through cogeneration technology in two different but related ways.

AB 1402. AB 1402 would require the State Energy Commission and the Public Utilities Commission jointly to conduct a review of standby rates which are charged by electric utilities to companies which employ cogeneration technology. (A standby rate is what a utility charges a company which employs cogeneration technology for the utility to provide standby generation, transmission and distribution facilities.) After conducting a review, the PUC would establish standby rates which would encourage the utilization of electricity produced through cogeneration technology and a reasonable return to electric utilities so that they would recover their costs of providing standby services.

AB 1402 also makes technical changes in the Public Utilities Code by renumbering sections dealing with automatic dialing-announcing devices.

AB 1403. AB 1403 requires the State Energy Commission and the Public Utilities Commission jointly to conduct a review of the compensation offered by utilities to companies which utilize cogeneration technology to produce electricity which can be sold to utilities. Following a review, the PUC would be required to approve and establish rates electric utilities must pay to companies from which they purchase electricity created by cogeneration technology. The PUC could act on its own motion, upon recommendation of the State Energy Commission or upon application from a private company.

AB 1403 also makes technical changes to sections of the Public Utilities Code by renumbering various sections dealing with automatic dialing-announcing devices.

COMMENTS

AB 1402 and AB 1403 were introduced by the author to encourage the development of electricity through cogeneration technology by requiring the PUC to establish standby rates and rates for purchasing electricity from companies which use cogeneration technology which will encourage electrical utilities to enter into contracts with companies utilizing cogeneration.

The PUC has been working on cogeneration since it initiated OII No. 26 last year to review Pacific Gas and Electric's resource plans for purchasing electricity from cogeneration sources. In two decisions issued on December 19, 1979 (OII No. 26 and Rate Case Decision 91107), the commission found that PG&E should have entered into contracts to purchase 3,000 megawatts of electricity from cogeneration sources. PG&E was ordered to enter into contracts to purchase 600 megawatts in 1980, 400 megawatts during 1981 and another 1,000 megawatts by 1985. PG&E was penalized $7 million on its rate of return for being deficient in entering contracts with cogenerators. However, the penalty will be removed when it satisfies the above contract schedule.

The December 19th decisions accomplish the intent of AB 1402 and AB 1403 because the decisions establish a bases for standby rates and compensation which must be paid for purchasing electricity from cogenerators. The decisions encourage cogeneration technology. The standby rates charged by utilities to companies utilizing cogeneration technology must be set at a utility's "average cost." That is, at a cost which averages the utility's high and low costs of producing electricity. "Average cost" pricing tends to be lower than other pricing methods.

The commission's decisions require that rates paid by utilities for electricity produced from a company which utilizes cogeneration technology must be at a utility's "avoided cost." "Avoided costs" reflect the costs of building new power plants to generate electricity that can be purchased elsewhere. Because construction costs are high and tend to reflect inflationary pressures, avoided costs are usually high. The result of the PUC's decisions is that PG&E will charge a lower rate for providing standby services to companies which utilize cogeneration technology than the companies will charge PG&E for electricity it purchases from them. Companies will be encouraged to enter into contracts with PG&E to purchase their electricity because of the favorable rates they can charge. PG&E will have to enter into contracts because of the decision of the PUC that it purchase 2,000 megawatts of electricity from cogeneration sources by 1985.

According to the PUC, it has been working with the State Energy Commission on an informal basis to analyze standby rates. This has resulted in a 46 percent reduction in standby rates charged by PG&E, Southern California Edison and SDG&E.

Technical Amendments

AB 1402 and AB 1403 would both add Section 2821 to the Public Utilities Code in different forms. Section 2821 in AB 1402 requires the commission to establish standby rates charged by electric utilities. Section 2821 in AB 1403 requires the commission to approve and establish rates paid by utilities for electricity purchased from companies which employ cogeneration technology. It is recommended that these two sections be combined into

one section in either bill in order to accomplish the author's purpose and to eliminate any chaptering problems.

The provisions of AB 1402 and AB 1403 apply only to private utilities regulated by the PUC. In order to further encourage cogeneration technology, the provisions of these bills should also apply to municipal utilities that produce electricity for the public.

The following have expressed interest in this measure:

Public Utilities Commission (neutral)